FOIA/PA NO: ___2013-0250_______

GROUP B

RECORDS BEING RELEASED IN THEIR ENTIRETY

Graff, Mark

From: Musser, Randy
Sent: Friday, February 17, 2012 10:46 AM
To: Bernhard, Rudolph
Cc: Taylor, Ryan; OBryan, Phil; Schwieg, Mark; Dodson, Jim; Worosilo, Jannette; Hopper, George
Subject: FW: Brunswick RPV Phase 1.docx
Attachments: Brunswick RPV Phase 1.docx

Rudy,

Attached is the approved phase 1 for your review involving the failure to properly fasten the Brunswick RPV head. Any questions, please let me know.

Randy

From: Taylor, Ryan
Sent: Friday, February 17, 2012 10:39 AM
To: Musser, Randy
Cc: OBryan, Phil
Subject: Brunswick RPV Phase 1.docx

Updated Phase 1

B1

Table 1- SDP PHASE 1 SCREENING WORKSHEET FOR ALL CORNERSTONES
Reference/Title (LER #, Inspection Report #, etc): 05000324/2011013-01: Failure to Properly Assemble Reactor Vessel Head Following Maintenance Outage
Performance Deficiency (concise statement clearly stating deficient licensee performance): The licensee's failure to follow plant procedures to ensure that the RPV head was properly reassembled following the Unit 2 maintenance outage was a performance deficiency. Three examples of failure to follow procedure included: 1) Failure to apply proper hydraulic pressure to the stud tensioners and failure to ensure that the stud elongation measurements were in tolerance represented non-compliances with procedure 0SMP-RPV502, Reactor VesselReassembly, Section 7.15, RPV Head Stud Tensioning. 2) Failure to provide adequate training to refueling floor workers and to assure that they had completed the proper qualification training represented non-compliances with procedure TRN-NGCC-1000, Conduct of Training. 3) Failure to perform a post maintenance test for the disassembly and reassembly of the RPV represented a non-compliance with 0PLP-20, Post Maintenance Testing.
Factual Description of Condition (statement of <u>facts</u> known about the condition that resulted from the performance deficiency, <u>without</u> hypothetical failures included.) Explain why issue is more than minor: On November 16, 2011, at 2:08 a.m., Brunswick Nuclear Plant Unit 2 calculated a drywall floor drain leak rate of 5.88 gpm following several hours of gradually rising floor drain leakage during a plant startup. Technical Specification 3.4.4 A was entered requiring floor drain leakage to be restored below 5 gpm within 8 hours. At 2:53 a.m., the calculated leak rate was 10.11 gpm. At 3:01 a.m., a NOUE was declared for unidentified leakage exceeding 10 gpm. At 3:09 a.m., the licensee initiated a manual reactor scram from approximately 7% power. Following the scram, reactor pressure was decreased and the unidentified leak rate dropped below 10 gpm within 1 hour and less than 5 gpm within 2 hours. The leak rate at 6:14 a.m. was 3.82 gpm with reactor pressure at 228 psig. On November 17, 2011, the licensee determined that the reactor head flange was leaking due to inadequate reactor vessel head stud tensioning. Inspectors reviewed the licensee's actions prior to the event and identified examples of improper procedure use and adherence that contributed to the inadequate reactor vessel head stud tensioning. (Please refer to the performance deficiency) The licensee's failure to follow plant procedures to ensure that the RPV head was properly reassembled following the Unit 2 maintenance outage was a performance deficiency. The performance deficiency was more than minor because it was associated with the Initiating Events cornerstone attribute of equipment performance and adversely affected the cornerstone objective in that the licensee's failure to properly reassemble the RPV head impacted the ability of the reactor coolant system to perform its critical safety function

System(s)/Train(s) Degraded by Condition or Programmatic Weakness (note that the safety functions affected must be those identified in the Site Specific Risk-Informed Inspection Notebooks): Reactor Coolant System
Licensing Basis Function of System(s)/Train(s) or Program: The reactor pressure vessel head is designed to form a leak-free seal, preventing the loss of reactor coolant and associated radioactivity release from the reactor vessel. This is accomplished by the use of reactor vessel flanges sealed by two concentric, silver plated or jacketed seal rings designed for no detectable leakage through the inner or outer seal at any operating condition.
Other Safety Function of System(s)/Train(s): The loss of steam from the reactor vessel to the primary containment also has the potential to challenge the integrity of the primary containment.
Maintenance Rule Category (check one): _X_ risk-significant ____ non risk-significant
Time condition existed or is assumed to have existed: The reactor head was reassembled on 11/13/11. The licensee declared entry into mode 4 at 0735 on 11/13/11, and entry into mode 2 at 0200 on 11/15/11. Reactor startup and pressurization continued throughout 11/15/11. The reactor was scrammed at 0309 on 11/16/11 and started cooling down. Mode four was declared at 1438 on 11/16/11. The head studs were discovered to be improperly tensioned at approximately 1300 on 11/17/11, and the reactor was declared to be in mode five.

Table 2 - CORNERSTONES AND FUNCTIONS DEGRADED AS A RESULT OF DEFICIENCY

(✔) Check the appropriate boxes

<table>
<tr><th>INITIATING EVENTS CORNERSTONE</th><th>MITIGATION SYSTEMS CORNERSTONE</th><th>BARRIERS CORNERSTONE</th></tr>
<tr>
<td>X Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.)

❐ Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.)

❐ Fire initiator contributor (e.g., transient loadings and combustibles, hotwork)

❐ Internal/external flooding initiator contributor</td>
<td>❐ Core Decay Heat Removal Degraded

❐ Short Term Heat Removal Degraded

❐ Primary (e.g., Safety Inj, [main feedwater, HPCI, and RCIC - BWR only])
____ High Pressure
____ Low Pressure
❐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs)

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

❐ Reactivity Control Degraded

❐ Seismic/Fire/Flood/Severe Weather Protection Degraded</td>
<td>❐ RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock).
Note: all other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone.

❐ Containment Barrier Degraded

❐ Reactor Containment Degraded
____ Actual Breach or Bypass
____ Heat Removal, Hydrogen or Pressure Control Degraded

❐ Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded

❐ Fuel Cladding Barrier Degraded

❐ Spent Fuel Pool

❐ Spent Fuel Pool Boiling

❐ Fuel Handling

❐ Spent Fuel Pool Inventory</td>
</tr>
<tr><th>EMERGENCY PREPAREDNESS CORNERSTONE</th><th>OCCUPATION RADIATION SAFETY CORNERSTONE</th><th>PUBLIC RADIATION SAFETY CORNERSTONE</th></tr>
<tr>
<td>❐ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard

❐ Actual Event Implementation Problem</td>
<td>❐ ALARA Planning or Work Controls

❐ Exposure or Over-exposure problem

❐ Ability to Assess Dose Compromised</td>
<td>❐ Radioactive Effluent Release Program

❐ Radioactive Environmental Monitoring Program

❐ Radioactive Material Control Program

❐ Transportation or Part 61</td>
</tr>
<tr><th>SECURITY CORNERSTONE</th><th></th><th></th></tr>
<tr>
<td>❐ Findings identified under the IMC-2201, Security and Safeguards Inspection Program</td>
<td></td>
<td></td>
</tr>
</table>

Table 3a - SDP PHASE 1 SCREENING WORKSHEET FOR <u>EMERGENCY PREPAREDNESS</u>, <u>OCCUPATIONAL & PUBLIC RADIATION</u>, AND <u>SECURITY</u> CORNERSTONES
IF *the finding is in the licensee's:* 1. emergency preparedness area, **THEN STOP. Go to** IMC 0609, Appendix B. 2. occupational radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix C. 3. public radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix D. 4. security area, **THEN STOP. Go to** IMC 0609, Appendix E.
Table 3b - SDP PHASE 1 SCREENING WORKSHEET FOR <u>INITIATING EVENTS</u>, <u>MITIGATION SYSTEMS</u>, AND <u>BARRIERS</u> CORNERSTONES

IF the finding affects:

1. fire protection defense-in-depth strategies involving: detection, suppression (equipment for both manual and automatic), barriers, fire prevention and administrative controls, and post fire safe shutdown systems, **THEN STOP. Go to** IMC 0609, Appendix F. Issues related to performance of the fire brigade are not included in Appendix F and require NRC management review using Appendix M.

2. the safety of a reactor during refueling outages, forced outages, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated, **THEN STOP. Go to** IMC 0609, Appendix G.

3. the operator licensing requalification program or simulator fidelity, **THEN STOP. Go to** IMC 0609, Appendix I.

4. steam generator tube integrity, **THEN STOP. Go to** IMC 0609, Appendix J.

5. the licensee's assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control," **THEN STOP. Go to** IMC 0609, Appendix K.

6. SSCs where existing SDP guidance is not adequate to provide reasonable estimates of the findings significance within the established SDP timeliness goal of 90 days, **THEN STOP. Go to** IMC 0609, Appendix M.

7. the safety of an operating reactor, **THEN IDENTIFY** the degraded cornerstone(s):

   x Initiating Event
   ☐ Mitigation Systems
   ☐ RCS Barrier (e.g., PTS issues)
   ☐ Fuel Barrier
   ☐ Containment Barriers

CONTINUE to the appropriate column in Table 4a - Characterization Worksheet.

NOTE: When assessing the significance of a finding affecting multiple cornerstones, the finding should be assigned to the cornerstone that best reflects the dominant risk of the finding.

Table 4a - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES

Initiating Events Cornerstone	Mitigation Systems Cornerstone	RCS or Fuel Barrier	Containment Barrier

LOCA Initiators

1. Assuming worst case degradation, would the finding result in exceeding the Tech Spec limit for any RCS leakage or could the finding have likely affected other mitigation systems resulting in a total loss of their safety function.

X **If YES → Stop. Go to Appendix A.**

☐ If NO, screen as Green.

Transient Initiators

1. 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 → Stop. Go to Appendix A.**

☐ If NO, screen as Green.

External Event Initiators

1. 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 confirmed not to result in loss of operability or functionality.[1]

☐ **If YES, screen as Green.**

☐ If NO, continue.

2. Does the finding represent a loss of system safety function?

☐ **If YES → Stop. Go to Appendix A.**

☐ If NO, continue.

3. Does the finding represent actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time?

☐ **If YES → Stop. Go to Appendix A.**

☐ 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 → Stop. Go to Appendix A.**

☐ If NO, continue.

5. Does the finding screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event, using the criteria on page 5 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.

RCS Barrier (e.g., pressurized thermal shock issues)

☐ **Stop. Go to Phase 3.**

Fuel Barrier

☐ Stop. Screen as Green.

Spent Fuel Pool Issues

1. Does the finding result in loss of cooling to the spent fuel pool, whereby operator or equipment failures could preclude restoration of cooling prior to pool boiling?

☐ **If YES** → Stop. Go to **Appendix M.**

☐ If NO, continue.

2. Does the finding result from fuel handling errors that caused damage to fuel clad integrity or a dropped assembly (includes ISFSI)?

☐ **If YES** → Stop. Go to **Appendix M.**

☐ If NO, continue.

3. Does the finding result in a loss of spent fuel pool inventory greater than 10% of SFP volume?

☐ **If YES** → Stop. Go to **Appendix A.**

☐ If NO, screen as Green.

1. Does the finding only represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, or SBGT system (BWR)?

☐ **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 → Stop. Go to Phase 3.**

☐ If NO, continue.

3. Does the finding represent an actual open pathway in the physical integrity of reactor containment (valves, airlocks, containment isolation system (logic and instrumentation), and heat removal components?

☐ **If YES → Stop. Go to Appendix H.**

☐ If NO, continue.

4. Does the finding involve an actual reduction in function of hydrogen ignitors in the reactor containment?

☐ **If YES → Stop. Go to Appendix H.**

☐ If NO, screen as Green.

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[1] per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment."

Table 4b - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES

Seismic, 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)?

   - ☐ **If YES** ➛ continue to question 2
   - ☐ If NO ➛ skip to question 3

2. If the equipment or safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of this 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 **two or more** Trains of a multi-train safety system or function;

   c) would degrade one or more Trains of a system that supports a safety system or function.

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

3. Does the finding involve the total 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, flooding, or severe weather event)?

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

Result of Phase 1 screening process:

☐ **Screen as Green** ☐ **Go to Phase 2** X **Go to Phase 3**

Important Assumptions:

The pre-solved worksheets of the phase 2 SDP do not address this condition because the RPV is not represented.

Performed by: Ryan Taylor/Phil O'Bryan Date: 2/14/12

Graff, Mark

From:	OBryan, Phil
Sent:	Wednesday, December 14, 2011 3:14 PM
To:	Bernhard, Rudolph; Taylor, Ryan; Stamm, Eric
Cc:	Musser, Randy
Subject:	Input for Brunswick reactor head SDP

Rudy, the question of the reactor head self-sealing was answered when the licensee did a leak check in cold shutdown after the event. Level was raised above the flange and water poured out of the head/flange interface (with just static pressure from a few feet of water). This demonstrates that damage to the o-rings essentially caused a breach in the reactor pressure boundary that could not be isolated. Remember also that the o-rings were continuing to degrade throughout the event. The maximum calculated leakage was 10.11 gpm, but it had doubled in about 45 minutes. We don't know how bad it would have gotten.

Ryan, we need to be sure this information is in the phase 1 SDP worksheet that we give Rudy.

Phil O'Bryan, USNRC
Brunswick Senior Resident Inspector
910-457-9531
phil.obryan@nrc.gov

B2

Brunswick Nuclear Plant
Unit 2 RPV Head Leak
December 8, 2011

Unit 2 Operations Log: 11/15 – 11/16/2011

11/15/2011 2:00:07 AM: Placed the Unit 2 Reactor Mode Switch in Startup/Hot Standby per 0TP-01

11/15/2011 5:28:21 AM: Unit 2 Reactor Critical

11/15/2011 5:41:01 AM: Reactor Pressure 5 PSIG

11/15/2011 6:22:54 AM: Unit Mode 2, Reactor Power: 1%, Reactor Pressure: 20 PSIG

11/15/2011 4:20:50 PM: Reactor Power 350 PSIG

11/15/2011 6:27:40 PM: Unit 2 Mode 2, Reactor Power 7%, Reactor Pressure 500 PSIG

11/15/2011 9:28:58 PM: Reactor Pressure 928 PSIG

11/16/2011 12:32:37 AM: Midnight floor drain leakage was calculated at 3.99 gpm, up from .10 gpm at 20:00

11/16/2011 2:12:55 AM: Drywell leak rate calculated at 5.88 gpm over last 42 minutes. Entered LIC 3.4.4 Condition A to reduce leakage to within limits within 8 hours. This is not reportable.

11/16/2011 2:53:43 AM: DW FD over last 45 minutes is 10.11 gpm. This is above the EAL threshold for Unusual Event

11/16/2011 3:01:41 AM: Declared Unusual Event for drywell leakage greater than 10 gpm

11/16/2011 3:09:05 AM: Inserted manual scram on U2 due to drywell leak rate

11/16/2011 3:29:00 AM: DW calculated leakage has averaged 10.11 gpm over the last 36 minutes

11/16/2011 4:00:00 AM: DW calculated leakage has averaged 6.42 gpm over the last 31 minutes

11/16/2011 4:30:16 AM: DW calculated leakage has averaged 5.27 gpm over the last 30 minutes, at 400 psig Reactor Pressure.

11/16/2011 5:00:28 AM: DWFD calculated leakage has averaged 3.73 gpm over the last 30 minutes, at 360 psig Reactor Pressure

11/16/2011 6:14:16 AM: The 74 minute Drywell Floor Drain leak rate is 3.92 gpm with Reactor Pressure at 228 psig

B3

11/16/2011 7:15:50 AM: The 54 minute Drywell Floor Drain leak rate is 3.04 gpm with Reactor Pressure at 183 psig

11/16/2011 8:00:35 AM: The 52 minute Drywell Floor Drain leak rate is 3.51 gpm with Reactor Pressure at 135 psig

11/16/2011 9:02:53 AM: The 62 minute Drywell Floor Drain leak rate is 2.23 gpm with Reactor Pressure at 110 psig

11/16/2011 10:00:12 AM: The 58 minute Drywell Floor Drain leak rate is 2.26 gpm with Reactor Pressure at 80 psig

11/16/2011 11:00:55 AM: The 61 minute Drywell Floor Drain leak rate is 2.98 gpm with Reactor Pressure at 60 psig

11/16/2011 11:17:12 AM: Reactor Pressure 55 psig

11/16/2011 1:10:06 PM: The 120 minute Drywell Floor Drain leak rate is 0.575 gpm with Reactor Pressure at 26 psig

11/16/2011 2:38:14 PM: Unit 2 has entered Mode 4

Table 1- SDP PHASE 1 SCREENING WORKSHEET FOR ALL CORNERSTONES
Reference/Title (LER #, Inspection Report #, etc): 05000324/2011013-01: Failure to Properly Assemble Reactor Vessel Head Following Maintenance Outage
Performance Deficiency (concise statement clearly stating deficient licensee performance): The licensee's failure to follow plant procedures to ensure that the RPV head was properly reassembled following the Unit 2 maintenance outage was a performance deficiency. Three examples of failure to follow procedure included: 1) Failure to apply proper hydraulic pressure to the stud tensioners and failure to ensure that the stud elongation measurements were in tolerance represented non-compliances with procedure 0SMP-RPV502, Reactor VesselReassembly, Section 7.15, RPV Head Stud Tensioning. 2) Failure to provide adequate training to refueling floor workers and to assure that they had completed the proper qualification training represented non-compliances with procedure TRN-NGCC-1000, Conduct of Training. 3) Failure to perform a post maintenance test for the disassembly and reassembly of the RPV represented a non-compliance with 0PLP-20, Post Maintenance Testing.
Factual Description of Condition (statement of <u>facts</u> known about the condition that resulted from the performance deficiency, <u>without</u> hypothetical failures included.) Explain why issue is more than minor: On November 16, 2011, at 2:08 a.m., Brunswick Nuclear Plant Unit 2 calculated a drywall floor drain leak rate of 5.88 gpm following several hours of gradually rising floor drain leakage during a plant startup. Technical Specification 3.4.4 A was entered requiring floor drain leakage to be restored below 5 gpm within 8 hours. At 2:53 a.m., the calculated leak rate was 10.11 gpm. At 3:01 a.m., a NOUE was declared for unidentified leakage exceeding 10 gpm. At 3:09 a.m., the licensee initiated a manual reactor scram from approximately 7% power. Following the scram, reactor pressure was decreased and the unidentified leak rate dropped below 10 gpm within 1 hour and less than 5 gpm within 2 hours. The leak rate at 6:14 a.m. was 3.82 gpm with reactor pressure at 228 psig. On November 17, 2011, the licensee determined that the reactor head flange was leaking due to inadequate reactor vessel head stud tensioning. Inspectors reviewed the licensee's actions prior to the event and identified examples of improper procedure use and adherence that contributed to the inadequate reactor vessel head stud tensioning. (Please refer to the performance deficiency) The licensee's failure to follow plant procedures to ensure that the RPV head was properly reassembled following the Unit 2 maintenance outage was a performance deficiency. The performance deficiency was more than minor because it was associated with the Initiating Events cornerstone attribute of equipment performance and adversely affected the cornerstone objective in that the licensee's failure to properly reassemble the RPV head impacted the ability of the reactor coolant system to perform its critical safety function

System(s)/Train(s) Degraded by Condition or Programmatic Weakness (note that the safety functions affected must be those identified in the Site Specific Risk-Informed Inspection Notebooks): Reactor Coolant System
Licensing Basis Function of System(s)/Train(s) or Program: The reactor pressure vessel head is designed to form a leak-free seal, preventing the loss of reactor coolant and associated radioactivity release from the reactor vessel. This is accomplished by the use of reactor vessel flanges sealed by two concentric, silver plated or jacketed seal rings designed for no detectable leakage through the inner or outer seal at any operating condition.
Other Safety Function of System(s)/Train(s): The loss of steam from the reactor vessel to the primary containment also has the potential to challenge the integrity of the primary containment.
Maintenance Rule Category (check one): _X_ risk-significant ____ non risk-significant
Time condition existed or is assumed to have existed: The reactor head was reassembled on 11/13/11. The licensee declared entry into mode 4 at 0735 on 11/13/11, and entry into mode 2 at 0200 on 11/15/11. Reactor startup and pressurization continued throughout 11/15/11. The reactor was scrammed at 0309 on 11/16/11 and started cooling down. Mode four was declared at 1438 on 11/16/11. The head studs were discovered to be improperly tensioned at approximately 1300 on 11/17/11, and the reactor was declared to be in mode five.

Table 2 - CORNERSTONES AND FUNCTIONS DEGRADED AS A RESULT OF DEFICIENCY (✔) Check the appropriate boxes		
INITIATING EVENTS CORNERSTONE	**MITIGATION SYSTEMS CORNERSTONE**	**BARRIERS CORNERSTONE**
X Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ❐ Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ❐ Fire initiator contributor (e.g., transient loadings and combustibles, hotwork) ❐ Internal/external flooding initiator contributor	❐ Core Decay Heat Removal Degraded ❐ Short Term Heat Removal Degraded ❐ Primary (e.g., Safety Inj, [main feedwater, HPCI, and RCIC - BWR only]) ___ High Pressure ___ Low Pressure ❐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ❐ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ❐ Reactivity Control Degraded ❐ Seismic/Fire/Flood/Severe Weather Protection Degraded	❐ RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). Note: all other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. ❐ Containment Barrier Degraded ❐ Reactor Containment Degraded ___ Actual Breach or Bypass ___ Heat Removal, Hydrogen or Pressure Control Degraded ❐ Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ❐ Fuel Cladding Barrier Degraded ❐ Spent Fuel Pool ❐ Spent Fuel Pool Boiling ❐ Fuel Handling ❐ Spent Fuel Pool Inventory
EMERGENCY PREPAREDNESS CORNERSTONE	**OCCUPATION RADIATION SAFETY CORNERSTONE**	**PUBLIC RADIATION SAFETY CORNERSTONE**
❐ **Failure to Comply with a Planning Standard or Risk-Significant Planning Standard** ❐ **Actual Event Implementation Problem**	❐ **ALARA Planning or Work Controls** ❐ **Exposure or Over-exposure problem** ❐ **Ability to Assess Dose Compromised**	❐ **Radioactive Effluent Release Program** ❐ **Radioactive Environmental Monitoring Program** ❐ **Radioactive Material Control Program** ❐ **Transportation or Part 61**
SECURITY CORNERSTONE		
❐ **Findings identified under the IMC-2201, Security and Safeguards Inspection Program**		

Table 3a - SDP PHASE 1 SCREENING WORKSHEET FOR EMERGENCY PREPAREDNESS, OCCUPATIONAL & PUBLIC RADIATION, AND SECURITY CORNERSTONES
IF the finding is in the licensee's: 1. emergency preparedness area, **THEN STOP. Go to** IMC 0609, Appendix B. 2. occupational radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix C. 3. public radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix D. 4. security area, **THEN STOP. Go to** IMC 0609, Appendix E.
Table 3b - SDP PHASE 1 SCREENING WORKSHEET FOR INITIATING EVENTS, MITIGATION SYSTEMS, AND BARRIERS CORNERSTONES

IF the finding affects:

1. fire protection defense-in-depth strategies involving: detection, suppression (equipment for both manual and automatic), barriers, fire prevention and administrative controls, and post fire safe shutdown systems, **THEN STOP. Go to** IMC 0609, Appendix F. Issues related to performance of the fire brigade are not included in Appendix F and require NRC management review using Appendix M.

2. the safety of a reactor during refueling outages, forced outages, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated, **THEN STOP. Go to** IMC 0609, Appendix G.

3. the operator licensing requalification program or simulator fidelity, **THEN STOP. Go to** IMC 0609, Appendix I.

4. steam generator tube integrity, **THEN STOP. Go to** IMC 0609, Appendix J.

5. the licensee's assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control," **THEN STOP. Go to** IMC 0609, Appendix K.

6. SSCs where existing SDP guidance is not adequate to provide reasonable estimates of the findings significance within the established SDP timeliness goal of 90 days, **THEN STOP. Go to** IMC 0609, Appendix M.

7. the safety of an operating reactor, **THEN IDENTIFY** the degraded cornerstone(s):

   x Initiating Event
   ☐ Mitigation Systems
   ☐ RCS Barrier (e.g., PTS issues)
   ☐ Fuel Barrier
   ☐ Containment Barriers

CONTINUE to the appropriate column in Table 4a - Characterization Worksheet.

NOTE: When assessing the significance of a finding affecting multiple cornerstones, the finding should be assigned to the cornerstone that best reflects the dominant risk of the finding.

Table 4a - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES

Initiating Events Cornerstone	Mitigation Systems Cornerstone	RCS or Fuel Barrier	Containment Barrier

<u>LOCA Initiators</u> 1. Assuming worst case degradation, would the finding result in exceeding the Tech Spec limit for any RCS leakage or could the finding have likely affected other mitigation systems resulting in a total loss of their safety function. X **If YES → Stop. Go to Appendix A.** □ If NO, screen as Green. <u>Transient Initiators</u> 1. Does the finding contribute to <u>both</u> the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions will not be available? □ **If YES → Stop. Go to Appendix A.** □ If NO, screen as Green. <u>External Event Initiators</u> 1. 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 confirmed <u>not</u> to result in loss of operability or functionality.[1] □ **If YES, screen as Green.** □ If NO, continue. 2. Does the finding represent a loss of system safety function? □ **If YES → Stop. Go to Appendix A.** □ If NO, continue. 3. Does the finding represent actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time? □ **If YES → Stop. Go to Appendix A.** □ 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 → Stop. Go to Appendix A.** □ If NO, continue. 5. Does the finding screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event, using the criteria on page 5 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.	<u>RCS Barrier</u> (e.g., pressurized thermal shock issues) □ **Stop. Go to Phase 3.** <u>Fuel Barrier</u> □ Stop. Screen as Green. <u>Spent Fuel Pool Issues</u> 1. Does the finding result in loss of cooling to the spent fuel pool, whereby operator or equipment failures could preclude restoration of cooling prior to pool boiling? □ **If YES** → Stop. Go to **Appendix M.** □ If NO, continue. 2. Does the finding result from fuel handling errors that caused damage to fuel clad integrity or a dropped assembly (includes ISFSI)? □ **If YES** → Stop. Go to **Appendix M.** □ If NO, continue. 3. Does the finding result in a loss of spent fuel pool inventory greater than 10% of SFP volume? □ **If YES** → Stop. Go to **Appendix A.** □ If NO, screen as Green.	1. Does the finding <u>only</u> represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, or SBGT system (BWR)? □ **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 → Stop. Go to Phase 3.** □ If NO, continue. 3. Does the finding represent an actual open pathway in the physical integrity of reactor containment (valves, airlocks, containment isolation system (logic and instrumentation), and heat removal components? □ **If YES → Stop. Go to Appendix H.** □ If NO, continue. 4. Does the finding involve an actual reduction in function of hydrogen ignitors in the reactor containment? □ **If YES → Stop. Go to Appendix H.** □ If NO, screen as Green.

[1] per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment."

Table 4b - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES
Seismic, 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)?

   - ☐ **If YES** ➛ continue to question 2
   - ☐ If NO ➛ skip to question 3

2. If the equipment or safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of this 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 **two or more** Trains of a multi-train safety system or function;

   c) would degrade one or more Trains of a system that supports a safety system or function.

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

3. Does the finding involve the total 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, flooding, or severe weather event)?

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

Result of Phase 1 screening process:

☐ **Screen as Green** ☐ **Go to Phase 2** X **Go to Phase 3**

Important Assumptions:

The pre-solved worksheets of the phase 2 SDP do not address this condition because the RPV is not represented.

Performed by: Ryan Taylor/Phil O'Bryan Date: 2/14/12

Cable	Route	SOURCE_N	Target Typ	Fire_Mode	HEAF	69 kW	143 kW	211 kW	317 kW	702 kW	OIL_010	OIL_100	Dist_rad	Target Set
0862F	3026;C170	FC35_S0682	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48.41487	FM
0868F	16072N	FC35_S0683	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0869F	16072N	FC35_S0683	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0865F	16072Q	FC35_S0684	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	HEAF
0866F	16072Q	FC35_S0684	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	HEAF
0868F	16072N	FC35_S0684	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	66.48308	HEAF
0869F	16072N	FC35_S0684	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	66.48308	HEAF
0870F	16072Q	FC35_S0684	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	HEAF
0862F	3035;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	12	HEAF
0862F	3064;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	12	HEAF
0865F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0865F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0866F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0866F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0867F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0867F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0868F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0868F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0869F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0869F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0870F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0870F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0871F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0871F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0872F	3032;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0872F	3033;C170	FC35_S0685	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0862F	3065;C170	FC35_S0686	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	HEAF
0865F	16072Q	FC35_S0689	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	FM
0865F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0866F	16072Q	FC35_S0689	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	FM
0866F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0867F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0868F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0869F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0870F	16072Q	FC35_S0689	C	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	FM
0870F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0871F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0872F	3043;C170	FC35_S0689	T	FALSE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	FM
0862F	3065;C170	FC35_S0694	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	20	211
0865F	16072Q	FC35_S0697	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	40	211
0866F	16072Q	FC35_S0697	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	40	211
0870F	16072Q	FC35_S0697	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	40	211
0865F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0866F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0867F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0868F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0869F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0870F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0871F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0872F	3033;C170	FC35_S0699	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	18	211
0862F	3024;C170	FC35_S0708	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	65.73431	FM
0862F	2994;C170	FC35_S0709	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	33.10589	702
0862F	3024;C170	FC35_S0709	T	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	64.03124	702
0862F	2994;C170	FC35_S0716	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	31.40064	702
0865F	16072Q	FC35_S0720	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	211
0865F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0866F	16072Q	FC35_S0720	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	211
0866F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0867F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0868F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0869F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0870F	16072Q	FC35_S0720	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	50	211
0870F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0871F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0872F	3043;C170	FC35_S0720	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	30	211
0862F	3026;C170	FC35_S0724	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48.41487	211
0868F	16072N	FC35_S0727	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	211
0869F	16072N	FC35_S0727	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	211
0862F	3065;C170	FC35_S0728	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	211
0862F	3035;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	12	FM
0862F	3064;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	12	FM
0865F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM

B-4

Cable	Route	SOURCE_N	Target Typ	Fire_Mode	HEAF	69 kW	143 kW	211 kW	317 kW	702 kW	OIL_010	OIL_100	Dist_rad	Target Set
0865F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0866F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0866F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0867F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0867F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0868F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0868F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0869F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0869F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0870F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0870F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0871F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0871F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0872F	3032;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0872F	3033;C170	FC35_S0729	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0865F	16072Q	FC35_S0731	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	211
0866F	16072Q	FC35_S0731	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	211
0868F	16072N	FC35_S0731	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	66.48308	211
0869F	16072N	FC35_S0731	C	FALSE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	66.48308	211
0870F	16072Q	FC35_S0731	C	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	48	211
0862F	3026;C170	FC35_S0732	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	54	702
0862F	3027;C170	FC35_S0732	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	54	702
0862F	3065;C170	FC35_S2949	T	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0862F	3065;C170	FC35_S2950	T	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	28	FM
0868F	16072N	FC35_S2951	C	TRUE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0869F	16072N	FC35_S2951	C	TRUE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0868F	16072N	FC35_S2952	C	TRUE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0869F	16072N	FC35_S2952	C	TRUE	FALSE	FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	FALSE	76.15773	FM
0862F	3034;C170	No source												
0862F	3072;C170	No source												
0872F	16072P	No source												
0872F	3031;C170	No source												

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Table 1- FINDING CONSOLIDATED INFORMATION SHEET
Supporting Documentation and References:
LER 400/2012-001-00, Delayed Closure of Main Steam Isolation Valves Due to Corrosion
HNP TS 3.7.1.5, Main Steam Line Isolation Valves
HNP FSAR 10.3, Main Steam Supply System
NRC Inspection Report 05000400/2012008
IMC 0612, IMC 0609
NRC Enforcement Manual
HNP NCR 531773 and 536078

B5

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Clearly Articulated Finding: A self-revealing (potentially greater than Green) Finding was identified for the licensee's **failure to properly classify the MSIVs as risk significant and conduct MSIV diagnostic testing of the MSIVs in accordance with EGR-NGGC-0205, Air Operated Valve Reliability Program**. This contributed to the licensee not identifying long-term corrosion/oxidation of the valve piston rings that resulted in the "B" and "C" MSIV failure to initially close during stroke time testing on April 21, 2012, and challenged the capability of the valves to perform their required closure function during certain design basis events. This finding resulted in an apparent violation of TS 3.7.1.5, Main Steam Line Isolation Valves, because the long-term valve degradation resulted in inoperability of the MSIVs greater than allowed by TS.

The failure to properly classify the MSIVs as risk significant and implement MSIV diagnostic testing in accordance with the AOV program procedure EGR-NGGC-0205 was a performance deficiency (PD). The PD is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objectives of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is also associated with the containment isolation barrier performance attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the failure to conduct periodic diagnostic testing that would have identified long-term internal valve degradation due to unexpected corrosion/oxidation of the valve piston rings in all three MSIVs resulted in two MSIVs failing to initially close during TS stroke time testing on April 21, 2012, and excessive internal friction in all three MSIVs such that they may not have been capable of performing their safety-related closure function during certain design basis events. The MSIVs are required to close within 5 seconds to mitigate the consequences of a SGTR event and MSLB events inside and outside containment. Using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," the inspectors determined there was an actual loss of safety function greater than the TS allowed outage time associated with the finding which required a more detailed risk evaluation. A detailed risk evaluation was performed by a regional senior reactor analyst which determined the safety significance to be (Color - George MacDonald to input Risk Evaluation Here)

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Factual Description of Degraded Condition or Programmatic Weakness: The MSIVs were inappropriately categorized in the AOV program as Category 2 versus Category 1. In 2001, the MSIVs were initially classified as Category 2 by the Maintenance Rule Expert Panel based on Probabilistic Safety Analysis (PSA) Model input at the time that considered only the containment isolation function of the valves for external radiological release mitigation. As such, the MSIVs were designated, along with all other containment isolation valves, as non-risk significant for Core Damage Frequency (CDF). In 2003, the PSA Model was updated, at which time it was recognized that the MSIVs performed not only a containment isolation function, but were important in the mitigation of SGTR and MSLB design basis events. While this update conciuded that the MSIVs were risk significant for CDF, the AOV program was not updated to reflect the change, which would have required the valves to be classified as Category 1.
Logical link(s) that Connect(s) the Finding to the Degraded Condition or Programmatic Weakness: If the MSIVs had been classified as Category 1, they would have been required to be diagnostically tested every three refueling outages. Therefore had the MSIVs been properly re-classified in the AOV program in 2003, in all likelihood, the high internal valve friction from the corrosion/oxidation phenomenon would have been identified via the periodic diagnostic testing in time for corrective action to have been taken prior to the April 21, 2012, stroke time failures. The exact time of failure cannot be determined. The last successful stroking of the MSIVs occurred on 11/7/10 which is 18 months, 2 weeks prior to this failure. Using the T/2 exposure time methodology, the exposure time for this failure is 9 months, 1 week. No cross-cutting aspect was assigned to this finding because licensee decisions made in regard to classifying the MSIVs in the AOV program were made more than three years ago and therefore, not reflective of current plant performance.

Table 2 – CORNERSTONES AFFECTED BY DEGRADED CONDITION OR PROGRAMMATIC WEAKNESS (✔) Check the appropriate boxes		
INITIATING EVENTS CORNERSTONE	**MITIGATION SYSTEMS CORNERSTONE**	**BARRIERS CORNERSTONE**

☐ A. Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ☐ B. Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ☐ D. Steam Generator Tube Rupture ☐ E. External Event initiators (limited to fire and internal flooding)	× ☐ A. Mitigating Systems × ☐ Core Decay Heat Removal Degraded ☐ Short Term Heat Removal Degraded ☐ Primary (e.g., Safety Injection –PWR only; main feedwater, HPCI, and RCIC - BWR only) High Pressure–Both Types Low Pressure–Both Types ☐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ☐ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ☐ B. External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded) ☐ C. Reactivity Control Systems Degraded (including Reactor Protection System) ☐ Uncontrolled Control Rod Movement ☐ Inadvertent RCS Dilution or Cold Water Injection ☐ Reactivity Management (e.g. exceed licensed power limit, command and control)	☐ A. RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). **Note**: All other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. × ☐ B. Reactor Containment Barrier Degraded × ☐ Actual Breach or Bypass (Such as leakage past penetrations seals, isolation valves that can contribute to ISLOCA, vent and purge system. Failure of systems/components critical to suppression pool integrity). ☐ Heat Removal, Hydrogen or Pressure Control Systems Degraded ☐ C. Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ☐ D. Spent Fuel Pool ☐ Maintaining subcritical conditions ☐ Spent Fuel Pool Water Inventory and /or Temperature (i.e., cooling) ☐ Fuel Handling

EMERGENCY PREPAREDNESS CORNERSTONE	OCCUPATION RADIATION SAFETY CORNERSTONE	PUBLIC RADIATION SAFETY CORNERSTONE
❒ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard ❒ Actual Event Implementation Problem	❒ ALARA Planning or Work Controls ❒ Exposure or Over-exposure problem ❒ Ability to Assess Dose Compromised	❒ Radioactive Effluent Release Program ❒ Radioactive Environmental Monitoring Program ❒ Radioactive Material Control Program ❒ Transportation or Part 61
SECURITY CORNERSTONE		
❒ Findings identified under the IMC-2201, Security and Safeguards Inspection Program		

Table 3 – SDP APPENDIX ROUTER
If the finding and associated degraded condition or programmatic weakness is in the licensee's: 1. Emergency Preparedness cornerstone, **STOP. Go to** IMC 0609, Appendix B. 2. Occupational Radiation Safety cornerstone, **STOP. Go to** IMC 0609, Appendix C. 3. Public Radiation Safety cornerstone, **STOP. Go to** IMC 0609, Appendix D. 4. Security cornerstone, **STOP. Go to** IMC 0609, Appendix E. 5. <u>Initiating Events, Mitigating Systems, or Barrier Integrity cornerstones, **CONTINUE** below:</u>

Read sections A thru E and answer the YES or NO questions. If NO is answered to all the questions in sections A thru E, the user is directed to Appendix A.

No was answered to all Sections A thru E, so go to Appendix A!

A. <u>Shutdown, Refueling, and Forced Outages:</u>

Does the finding pertain to operations, an event, or a degraded condition while the plant was shutdown?

NOTE: Appendix G is applicable during refueling, forced, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated and ends when RHR has been secured during plant heat-up.

☐ a. **If YES → STOP. Go to** IMC 0609, Appendix G.

☐ b. **If NO → Continue**

B. <u>Licensed Operator Requalification:</u>

Does the finding involve the operator licensing requalification program or simulator fidelity?

☐ a. **If YES →STOP. Go to** IMC 0609, Appendix I.

☐ b. **If NO → Continue**

C. <u>Maintenance Rule Risk Assessments:</u>

Does the finding involve the licensee's assessment and management of risk associated with

performing maintenance activities under all plant (operating or shutdown) conditions in accordance 10 CFR 50.65(a)(4) and the Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control"?

☐ a. **If YES →STOP. Go to** IMC 0609, Appendix K.

☐ b. **If NO → Continue**

D. <u>10 CFR 50.54(hh)(2) Mitigating Strategies:</u>

Is the finding associated with the mitigating strategies to maintain or restore core cooling, containment, and spent fuel pool cooling?

☐ a. **If YES → STOP. Go to** IMC 0609, Appendix L.

☐ b. **If NO**, **Continue**

E. <u>Fire Protection:</u>

1. Does the finding involve discrepancies with the fire brigade?

☐ a. **If YES → STOP. Go to** IMC 0609, Appendix A.

☐ b. **If NO, Continue**

2. Does the finding involve: (1) A failure to adequately implement fire prevention and administrative controls for transient combustible materials, transient ignition sources, or hot work activities? (2) Fixed fire protection systems or the ability to confine a fire? (3) Or affect the ability to reach and maintain safe shutdown conditions in case of a fire?

☐ a. **If YES → STOP. Go to** IMC 0609, Appendix F.

☐ b. **If NO → STOP. Go to** IMC 0609, Appendix A.

APPENDIX A

THE SIGNIFICANCE DETERMINATION PROCESS (SDP) FOR FINDINGS AT-POWER

Note: Both the Mitigating Systems cornerstone and Barrier Integrity cornerstone were affected. Per guidance in Appendix A, for the purposes of the power reactor assessment program, the Mitigating Systems Screening Questions were used since it was considered that this cornerstone captures the majority fraction of the overall risk.

Exhibit 2 – Mitigating Systems Screening Questions

A. Mitigating SSCs and Functionality (except Reactivity Control Systems – see section C below)

1. If the finding is a deficiency affecting the design or qualification

   - ☐ If **YES ➛Screen as Green.**
   - ☐ b. If NO, continue.

2. Does the finding represent a loss of system and/or function?

   - ☐ a. If **YES ➛Stop. Go to Detailed Risk Evaluation section.**
   - ☐ b. If NO, continue.

3. Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?

   - ☐ a. If **YES ➛Stop. Go to Detailed Risk Evaluation section.**

Answered YES, therefore go to Detailed Risk Evaluation section requiring SRA to arrive at appropriate risk evaluation.

> TS 3.7.1.5 requires that each MSIV shall be operable when operating in Modes 1, 2, 3, and 4. With one MSIV open and inoperable, operation may continue provided the inoperable MSIV is either closed (applicable in Modes 2, 3, or 4) or restored to an operable condition within 4 hours (applicable in Mode 1), otherwise be in Hot Standby within the next 6 hours and in Hot Shutdown within the following 6 hours. Based on the long-term nature of the degradation and the results of the licensee's as-found diagnostic test data, the inspectors determined that there was reasonable justification to conclude that all three MSIVs had been inoperable greater than the allowed outage time of TS 3.7.1.5.

   - ☐ b. If NO, continue.

4. Does the finding represent an actual loss of function of one or more non-Tech Spec Trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule program for >24 hrs?

   - ☐ a. If **YES ➛Stop. Go to Detailed Risk Evaluation section.**

☐ b. If **NO, screen as Green**.

B. External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded)

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)?

☐ a. If **YES →Go to Table 1**

☐ b. If **NO →screen as Green**

C. Reactivity Control Systems

1. Did the finding affect a single reactor protection system (RPS) trip signal to initiate a reactor scram AND the function of other redundant trips or diverse methods of reactor shutdown (e.g., other automatic RPS trips, alternate rod insertion, or manual reactor trip capacity)?

☐ a. If **YES →Stop. Go to Detailed Risk Evaluation section.**

☐ b. If NO, continue.

2. Did the finding involve control manipulations that unintentionally added positive reactivity (e.g., inadvertent boron dilution, cold water injection, inadvertent control rod movement, recirculation pump speed control)?

☐ a. If **YES, →Stop. Go to IMC 0609, Appendix M**

☐ b. If NO, continue

3. Did the finding result in a mismanagement of reactivity by operator(s) (e.g., reactor power exceeding the licensed power limit, inability to anticipate and control changes in reactivity during crew operations)?

☐ a. If **YES, →Stop. Go to IMC 0609, Appendix M**

☐ b. **If NO, screen as Green**

D. Fire Brigade

1. Does the finding involve Fire Brigade training and qualification requirements, or brigade staffing?

- ☐ a. If **YES ➛check if one or more of the following apply:**
  - ☐ The fire brigade demonstrated the ability to meet the required times for fire extinguishment for the fire drill scenarios, and the finding did not significantly affect the ability of the fire brigades to respond to a fire.
  - ☐ The overall time duration (exposure time) that the Fire Brigade was understaffed was short (< 2 hours).
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ c. If NO, continue

2. Does the finding involve the response time of the fire brigade to a fire?

- ☐ a. **If YES ➛check if one or more of the following apply:**
  - ☐ The fire brigade's response time was mitigated by other defense-in-depth elements, such as area combustible loading limits were not exceeded, installed fire detection systems were functional, and alternate means of safe shutdown were not impacted.
  - ☐ The finding involved risk-significant fire areas that had automatic suppression systems.
  - ☐ The licensee had adequate Fire Protection compensatory actions in place.
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ If NO, continue

3. Does the finding involve fire extinguishers, fire hoses, or fire hose stations?

- ☐ a. If **YES ➛check if one or more of the following apply:**
  - ☐ There was no degraded fire barrier and the fire scenario did not require the use of water to extinguish the fire.
  - ☐ The missing fire extinguisher or fire hose was missing for a short time and other extinguishers or hose stations were in the vicinity.
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ c. If none of the boxes under D.1.a, D.2.a, or D.3.a are checked ➛**Stop. Go to IMC 0609, Appendix M.**

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Table 1- FINDING CONSOLIDATED INFORMATION SHEET
Supporting Documentation and References:
LER 400/2012-001-00, Delayed Closure of Main Steam Isolation Valves Due to Corrosion
HNP TS 3.7.1.5, Main Steam Line Isolation Valves
HNP FSAR 10.3, Main Steam Supply System
NRC Inspection Report 05000400/2012008
IMC 0612, IMC 0609
NRC Enforcement Manual
HNP NCR 531773 and 536078

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Clearly Articulated Finding: A self-revealing (potentially greater than Green) Finding was identified for the licensee's **failure to properly classify the MSIVs as risk significant and conduct MSIV diagnostic testing of the MSIVs in accordance with EGR-NGGC-0205, Air Operated Valve Reliability Program**. This contributed to the licensee not identifying long-term corrosion/oxidation of the valve piston rings that resulted in the "B" and "C" MSIV failure to initially close during stroke time testing on April 21, 2012, and challenged the capability of the valves to perform their required closure function during certain design basis events. This finding resulted in an apparent violation of TS 3.7.1.5, Main Steam Line Isolation Valves, because the long-term valve degradation resulted in inoperability of the MSIVs greater than allowed by TS.

The failure to properly classify the MSIVs as risk significant and implement MSIV diagnostic testing in accordance with the AOV program procedure EGR-NGGC-0205 was a performance deficiency (PD). The PD is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objectives of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is also associated with the containment isolation barrier performance attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the failure to conduct periodic diagnostic testing that would have identified long-term internal valve degradation due to unexpected corrosion/oxidation of the valve piston rings in all three MSIVs resulted in two MSIVs failing to initially close during TS stroke time testing on April 21, 2012, and excessive internal friction in all three MSIVs such that they may not have been capable of performing their safety-related closure function during certain design basis events. The MSIVs are required to close within 5 seconds to mitigate the consequences of a SGTR event and MSLB events inside and outside containment. Using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," the inspectors determined there was an actual loss of safety function greater than the TS allowed outage time associated with the finding which required a more detailed risk evaluation. A detailed risk evaluation was performed by a regional senior reactor analyst which determined the safety significance to be (Color - George MacDonald to input Risk Evaluation Here)

HARRIS
TS INOPERABILITY OF ALL MSIVs DUE TO FAILURE TO CONDUCT DIAGNOSTIC TESTING

Factual Description of Degraded Condition or Programmatic Weakness: The MSIVs were inappropriately categorized in the AOV program as Category 2 versus Category 1. In 2001, the MSIVs were initially classified as Category 2 by the Maintenance Rule Expert Panel based on Probabilistic Safety Analysis (PSA) Model input at the time that considered only the containment isolation function of the valves for external radiological release mitigation. As such, the MSIVs were designated, along with all other containment isolation valves, as non-risk significant for Core Damage Frequency (CDF). In 2003, the PSA Model was updated, at which time it was recognized that the MSIVs performed not only a containment isolation function, but were important in the mitigation of SGTR and MSLB design basis events. While this update concluded that the MSIVs were risk significant for CDF, the AOV program was not updated to reflect the change, which would have required the valves to be classified as Category 1.
Logical link(s) that Connect(s) the Finding to the Degraded Condition or Programmatic Weakness: If the MSIVs had been classified as Category 1, they would have been required to be diagnostically tested every three refueling outages. Therefore had the MSIVs been properly re-classified in the AOV program in 2003, in all likelihood, the high internal valve friction from the corrosion/oxidation phenomenon would have been identified via the periodic diagnostic testing in time for corrective action to have been taken prior to the April 21, 2012, stroke time failures. No cross-cutting aspect was assigned to this finding because licensee decisions made in regard to classifying the MSIVs in the AOV program were made more than three years ago and therefore, not reflective of current plant performance.

Table 2 – CORNERSTONES AFFECTED BY DEGRADED CONDITION OR PROGRAMMATIC WEAKNESS (✔) Check the appropriate boxes		
INITIATING EVENTS CORNERSTONE	**MITIGATION SYSTEMS CORNERSTONE**	**BARRIERS CORNERSTONE**

❒ A. Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ❒ B. Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ❒ D. Steam Generator Tube Rupture ❒ E. External Event initiators (limited to fire and internal flooding)	X ❒ A. Mitigating Systems X ❒ Core Decay Heat Removal Degraded ❒ Short Term Heat Removal Degraded ❒ Primary (e.g., Safety Injection –PWR only; main feedwater, HPCI, and RCIC - BWR only) High Pressure–Both Types Low Pressure–Both Types ❒ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ❒ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ❒ B. External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded) ❒ C. Reactivity Control Systems Degraded (including Reactor Protection System) ❒ Uncontrolled Control Rod Movement ❒ Inadvertent RCS Dilution or Cold Water Injection ❒ Reactivity Management (e.g. exceed licensed power limit, command and control)	❒ A. RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). **Note**: All other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. X ❒ B. Reactor Containment Barrier Degraded X ❒ Actual Breach or Bypass (Such as leakage past penetrations seals, isolation valves that can contribute to ISLOCA, vent and purge system. Failure of systems/components critical to suppression pool integrity). ❒ Heat Removal, Hydrogen or Pressure Control Systems Degraded ❒ C. Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ❒ D. Spent Fuel Pool ❒ Maintaining subcritical conditions ❒ Spent Fuel Pool Water Inventory and /or Temperature (i.e., cooling) ❒ Fuel Handling

EMERGENCY PREPAREDNESS CORNERSTONE	OCCUPATION RADIATION SAFETY CORNERSTONE	PUBLIC RADIATION SAFETY CORNERSTONE
❐ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard ❐ Actual Event Implementation Problem	❐ ALARA Planning or Work Controls ❐ Exposure or Over-exposure problem ❐ Ability to Assess Dose Compromised	❐ Radioactive Effluent Release Program ❐ Radioactive Environmental Monitoring Program ❐ Radioactive Material Control Program ❐ Transportation or Part 61
SECURITY CORNERSTONE		
❐ Findings identified under the IMC-2201, Security and Safeguards Inspection Program		

Table 3 – SDP APPENDIX ROUTER
If the finding and associated degraded condition or programmatic weakness is in the licensee's: 1. Emergency Preparedness cornerstone, **STOP. Go to** IMC 0609, Appendix B. 2. Occupational Radiation Safety cornerstone, **STOP. Go to** IMC 0609, Appendix C. 3. Public Radiation Safety cornerstone, **STOP. Go to** IMC 0609, Appendix D. 4. Security cornerstone, **STOP. Go to** IMC 0609, Appendix E. 5. Initiating Events, Mitigating Systems, or Barrier Integrity cornerstones, **CONTINUE** below:
Read sections A thru E and answer the YES or NO questions. If NO is answered to all the questions in sections A thru E, the user is directed to Appendix A. No was answered to all Sections A thru E, so go to Appendix A! A. Shutdown, Refueling, and Forced Outages: Does the finding pertain to operations, an event, or a degraded condition while the plant was shutdown? NOTE: Appendix G is applicable during refueling, forced, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated and ends when RHR has been secured during plant heat-up. □ a. **If YES → STOP. Go to** IMC 0609, Appendix G. □ b. **If NO → Continue** B. Licensed Operator Requalification: Does the finding involve the operator licensing requalification program or simulator fidelity? □ a. **If YES →STOP. Go to** IMC 0609, Appendix I. □ b. **If NO → Continue** C. Maintenance Rule Risk Assessments: Does the finding involve the licensee's assessment and management of risk associated with

performing maintenance activities under all plant (operating or shutdown) conditions in accordance 10 CFR 50.65(a)(4) and the Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control"?

- ☐ a. **If YES ➛STOP. Go to** IMC 0609, Appendix K.
- ☐ b. **If NO ➛ Continue**

D. <u>10 CFR 50.54(hh)(2) Mitigating Strategies:</u>

Is the finding associated with the mitigating strategies to maintain or restore core cooling, containment, and spent fuel pool cooling?

- ☐ a. **If YES ➛ STOP. Go to** IMC 0609, Appendix L.
- ☐ b. **If NO, Continue**

E. <u>Fire Protection:</u>

1. Does the finding involve discrepancies with the fire brigade?
   - ☐ a. **If YES ➛ STOP. Go to** IMC 0609, Appendix A.
   - ☐ b. **If NO, Continue**
2. Does the finding involve: (1) A failure to adequately implement fire prevention and administrative controls for transient combustible materials, transient ignition sources, or hot work activities? (2) Fixed fire protection systems or the ability to confine a fire? (3) Or affect the ability to reach and maintain safe shutdown conditions in case of a fire?
   - ☐ a. **If YES ➛ STOP. Go to** IMC 0609, Appendix F.
   - ☐ b. **If NO ➛ STOP. Go to** IMC 0609, Appendix A.

APPENDIX A

THE SIGNIFICANCE DETERMINATION PROCESS (SDP) FOR FINDINGS AT-POWER

Note: Both the Mitigating Systems cornerstone and Barrier Integrity cornerstone were affected. Per guidance in Appendix A, for the purposes of the power reactor assessment program, the Mitigating Systems Screening Questions were used since it was considered that this cornerstone captures the majority fraction of the overall risk.

Exhibit 2 – Mitigating Systems Screening Questions

A. Mitigating SSCs and Functionality (except Reactivity Control Systems – see section C below)

1. If the finding is a deficiency affecting the design or qualification

   □ If **YES** ➛**Screen as Green.**

   □ b. If NO, continue.

2. Does the finding represent a loss of system and/or function?

   □ a. If **YES** ➛**Stop. Go to Detailed Risk Evaluation section.**

   □ b. If NO, continue.

3. Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?

   □ a. If **YES** ➛**Stop. Go to Detailed Risk Evaluation section.**

Answered YES, therefore go to Detailed Risk Evaluation section requiring SRA to arrive at appropriate risk evaluation.

> TS 3.7.1.5 requires that each MSIV shall be operable when operating in Modes 1, 2, 3, and 4. With one MSIV open and inoperable, operation may continue provided the inoperable MSIV is either closed (applicable in Modes 2, 3, or 4) or restored to an operable condition within 4 hours (applicable in Mode 1), otherwise be in Hot Standby within the next 6 hours and in Hot Shutdown within the following 6 hours. Based on the long-term nature of the degradation and the results of the licensee's as-found diagnostic test data, the inspectors determined that there was reasonable justification to conclude that all three MSIVs had been inoperable greater than the allowed outage time of TS 3.7.1.5.

   □ b. If NO, continue.

4. Does the finding represent an actual loss of function of one or more non-Tech Spec Trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule program for >24 hrs?

   □ a. If **YES** ➛**Stop. Go to Detailed Risk Evaluation section.**

□ b. If **NO, screen as Green**.

B. External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded)

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)?

□ a. If **YES ➛Go to Table 1**

□ b. If **NO ➛screen as Green**

C. Reactivity Control Systems

1. Did the finding affect a single reactor protection system (RPS) trip signal to initiate a reactor scram AND the function of other redundant trips or diverse methods of reactor shutdown (e.g., other automatic RPS trips, alternate rod insertion, or manual reactor trip capacity)?

   □ a. If **YES ➛Stop. Go to Detailed Risk Evaluation section.**

   □ b. If NO, continue.

2. Did the finding involve control manipulations that unintentionally added positive reactivity (e.g., inadvertent boron dilution, cold water injection, inadvertent control rod movement, recirculation pump speed control)?

   □ a. If **YES, ➛Stop. Go to IMC 0609, Appendix M**

   □ b. If NO, continue

3. Did the finding result in a mismanagement of reactivity by operator(s) (e.g., reactor power exceeding the licensed power limit, inability to anticipate and control changes in reactivity during crew operations)?

   □ a. If **YES, ➛Stop. Go to IMC 0609, Appendix M**

   □ b. If **NO, screen as Green**

D. Fire Brigade

1. Does the finding involve Fire Brigade training and qualification requirements, or brigade staffing?

- ☐ a. If **YES ➛check if one or more of the following apply:**
  - ☐ The fire brigade demonstrated the ability to meet the required times for fire extinguishment for the fire drill scenarios, and the finding did not significantly affect the ability of the fire brigades to respond to a fire.
  - ☐ The overall time duration (exposure time) that the Fire Brigade was understaffed was short (< 2 hours).
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ c. If NO, continue

2. Does the finding involve the response time of the fire brigade to a fire?

- ☐ a. **If YES ➛check if one or more of the following apply:**
  - ☐ The fire brigade's response time was mitigated by other defense-in-depth elements, such as area combustible loading limits were not exceeded, installed fire detection systems were functional, and alternate means of safe shutdown were not impacted.
  - ☐ The finding involved risk-significant fire areas that had automatic suppression systems.
  - ☐ The licensee had adequate Fire Protection compensatory actions in place.
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ If NO, continue

3. Does the finding involve fire extinguishers, fire hoses, or fire hose stations?

- ☐ a. If **YES ➛check if one or more of the following apply:**
  - ☐ There was no degraded fire barrier and the fire scenario did not require the use of water to extinguish the fire.
  - ☐ The missing fire extinguisher or fire hose was missing for a short time and other extinguishers or hose stations were in the vicinity.
- ☐ b. **If at least one of the above is checked ➛screen as Green.**
- ☐ c. If none of the boxes under D.1.a, D.2.a, or D.3.a are checked ➛**Stop. Go to IMC 0609, Appendix M.**

Briefing on Catawba Consequential LOOP SDP

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NRR/DRA

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Region II

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

July 13, 2012

B6

Purpose

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

- Provide background on the performance deficiency (PD) on the inadequate design of switchyard protective relaying resulting in a consequential LOOP condition (reactor trip combined with LOOP) at Catawba Units 1 and 2

- Discuss SDP Phase 3 analysis developed by Region II SRA

- Provide a recommendation on the course of action regarding this finding

Background

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- On **April 4, 2012**, Catawba Nuclear Station Unit 1 operating at 100% and Unit 2 in cold shutdown (fuel in the reactor, RHR mode).
- At **~8:03PM**, RCP ground fault in Unit 1 results in reactor trip on low flow, turbine trip and opening of generator output breakers, as designed.
  - However, powered circuit breakers (PCBs) in the switchyard also opened causing a total LOOP to Unit 1 **(i.e., consequential loop, C-LOOP)**.
  - Power to Unit 2 vital busses was being supplied through Unit 1 via cross connections at 4kV buses, hence loss of power to Unit 2 vital bus as well.
  - Unit 2 RHR pump restarted to restore decay heat removal **(8:06PM)**.
- At **8:12PM**, a Notice of Unusual Event (NOUE) was declared due to loss of offsite power to all essential busses.
  - The 1A, 2A, and 2B EDGs automatically started 15 seconds later due to LOOP to their respective essential busses.
- On **April 5, 2012**, at **1:37AM** the NOUE was terminated when power was restored to one essential bus on both Unit 1 and Unit 2.

Root Cause Analysis

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- During Spring 2011 refueling outage, modification implemented on the generator protection relay for Unit 1.
- One of the relay functions was an under-frequency (UF) relay to protect the generator by opening the switchyard breakers connected to the generator in case of a grid disturbance
  - Design requirements included "off-line" block for the generator UF relay functions (UF blocked if output breakers open).
  - Licensee did not develop testing procedures from the original design specifications (replacement considered a non-QA-1 modification).
- However, programming error resulted in "off-line" block being omitted by the relay vendor for the instantaneous UF relay
- NRC inspectors identified multiple missed opportunities to discover the programming error during the testing phase of the modification.
- Consequently, programming error propagated through the implementation phase undetected (placed in Unit 2, Spring 2012).

Power Distribution

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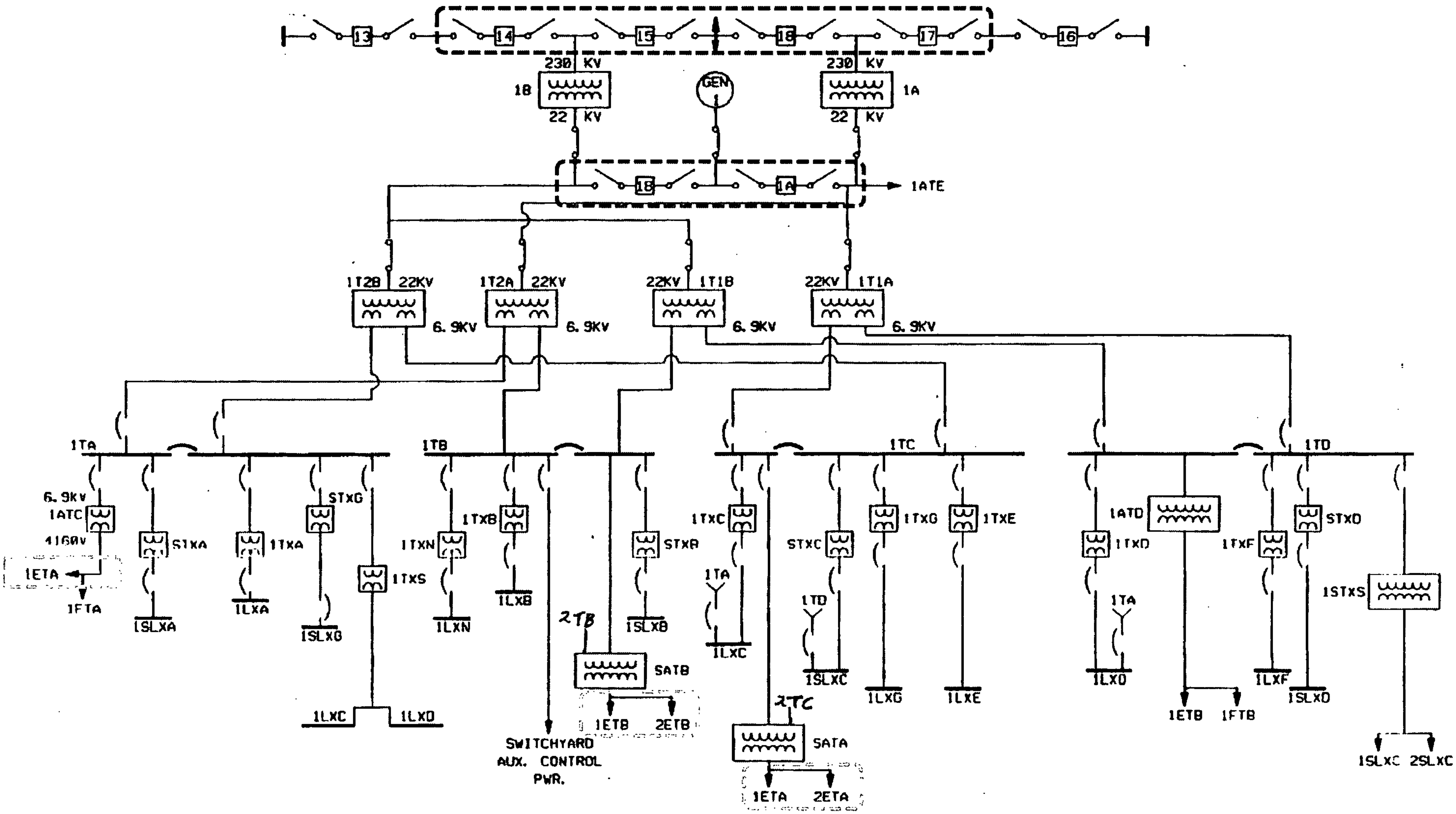

Performance Deficiency

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- Inadequate design of switchyard protective relaying resulting in loss of offsite power.

- Licensee failed to follow the requirements of EDM-141 procedure, "Procurement Specifications for Services," for providing design information to the vendor for programming the digital processors associated wit the UF protective relays

- Adverse effect on availability and reliability of the Equipment Performance attribute and adversely affected the Mitigating Systems cornerstone objective: offsite power supply would not have been available to respond to expected operational transients.

Exposure Time

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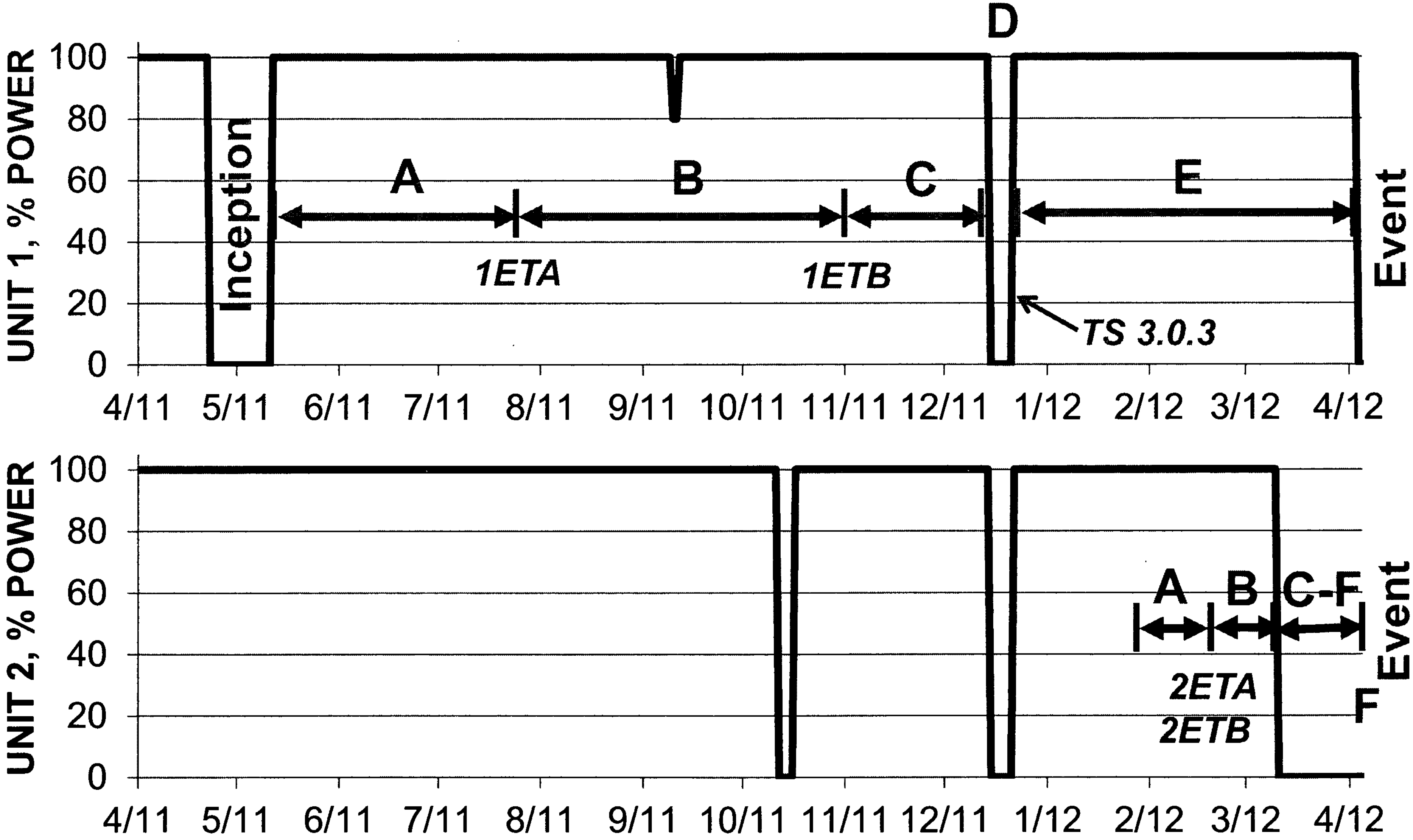

SDP Phase 3 Overview

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Protecting People and the Environment

- Catawba SPAR model modified to account for consequential LOOP scenarios (e.g., TRANS with LOOP) to account for LOOP and associated recoveries
- Analysis in individual Units/time windows performed with different assumptions for different conditions
  - Loss of vital bus on specific alignments
  - Unavailability of EDGs
  - Increase in LOOP frequency due to PD
- Boundary Conditions
  - Controlled shutdown vs. turbine trip from high power
  - Plant centered and switchyard- related LOOP
  - Nominal (generic) recovery actions credited

Exposure Time, Unit 1

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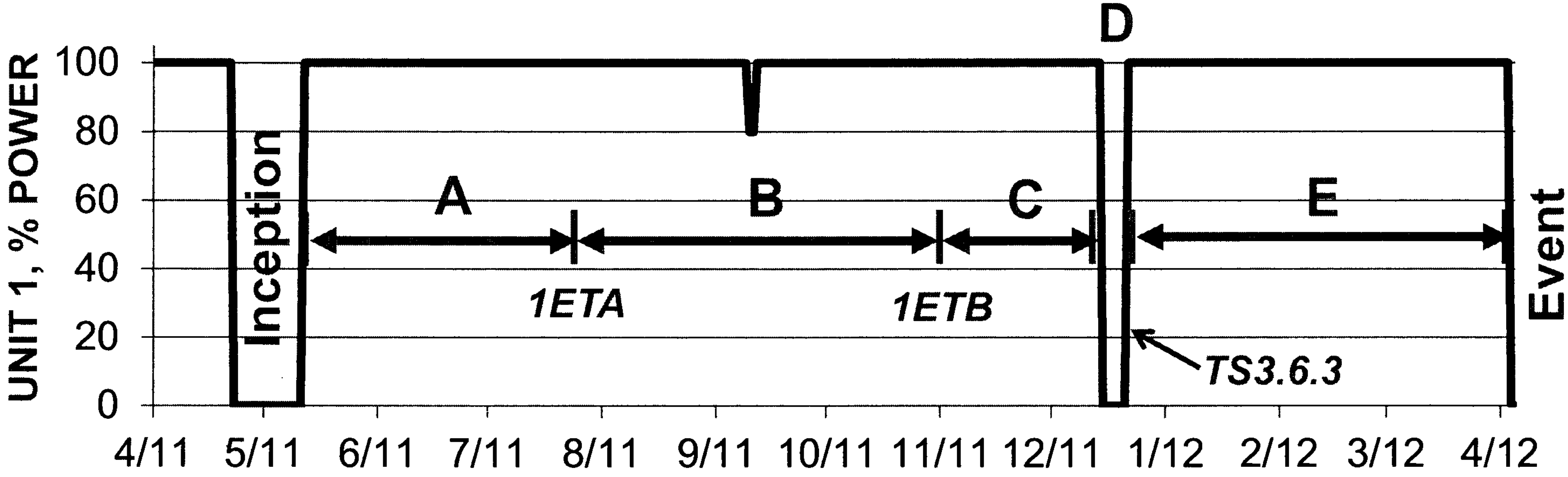

Window A:	Unit 1 restart, both Unit 1 vital busses aligned to Unit 2 (minimal risk not quantified)
Window B:	1ETA aligned back to Unit 1, 1ETB aligned to Unit 2 (loss of ETA, 105 days total)
Window C:	Both busses aligned back to Unit 1 (C-LOOP, 40 days)
Window D:	Unit 1 & 2 shutdown due to TS 3.0.3 (not quantified)
Window E:	Same as C, busses aligned to Unit 1 (C-LOOP, 105 days)

SDP Phase 3, Unit 1

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Protecting People and the Environment

ΔCDF Window B (Loss of ETA)

- All sequences + HEP recovery (1E-2)
- Availability of the EDGs and/or the cross-unit electrical feed
- ΔCDF = 3.1E-6/year for exposure time

ΔCDF Windows C & E (C-LOOP)

- Includes TRANS, LOACA, LOCHS, SGTR, LOMFW, LODCB, LOIA
- Excludes MLOCA, LLOCA, ISL-HPI/LPI/RHR, XLOCA (low frequency) and SORV, LONSW, LOCCW, SLOCA (not modeled)
- ΔCDF = 4.4E-5/year for exposure time

ΔLERF • Approximated from LOOP, SGTR (> 1E-7/year)

External Events

- Flooding/seismic screened
- Δ risk from fire approximated

Preliminary Results, Unit 1

- Unit 1 Total ΔCDF = YELLOW

Significance Determination Process (IMC0609): Estimated CDF (per year)			
CDF < 1E-6	**1E-6 ↔ 1E-5**	**1E-5 ↔ 1E-4**	**CDF > 1E-4**
GREEN			
VERY LOW	**WHITE**		
	LOW TO MODERATE	**YELLOW**	
		SUBSTANTIAL	**RED**
			HIGH

- Unit 1 Total ΔLERF = YELLOW

Significance Determination Process (IMC0609): Estimated LERF (per year)			
LERF < 1E-7	**1E-7 ↔ 1E-6**	**1E-6 ↔ 1E-5**	**LERF > 1E-5**
GREEN			
VERY LOW	**WHITE**		
	LOW TO MODERATE	**YELLOW**	
		SUBSTANTIAL	**RED**
			HIGH

Exposure Time, Unit 2

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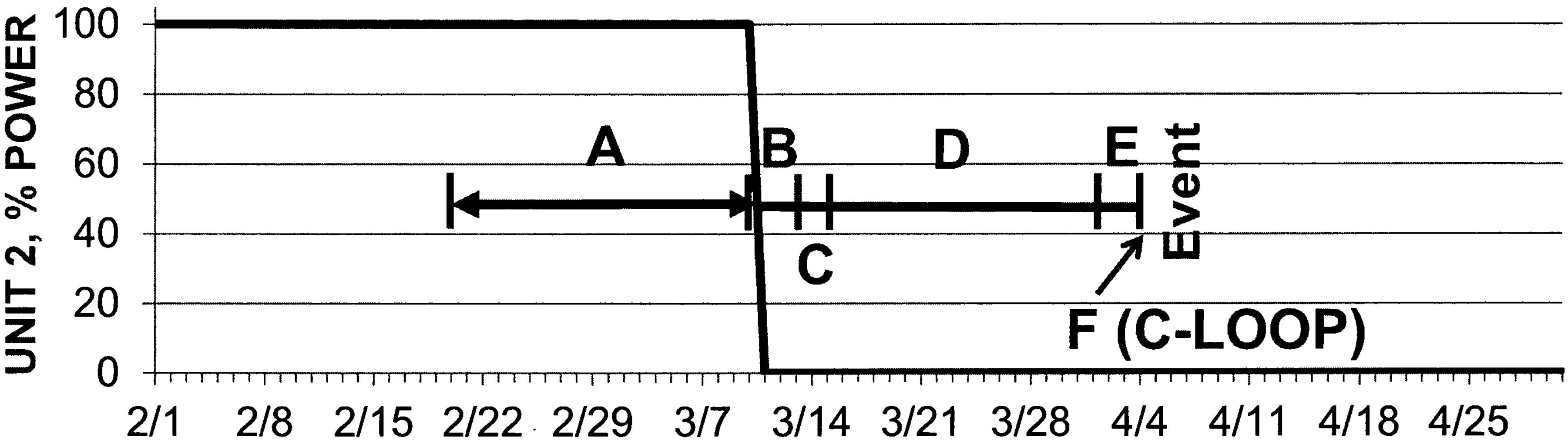
Protecting People and the Environment



<u>Window A:</u> Unit 2 vital busses aligned to Unit 1 ahead of shutdown, at-power with increased LOOP likelihood (19 days)

<u>Window B:</u> Mode 5, both trains of RHR available and 2B EDG out for extensive maintenance (64 hours)

<u>Window C:</u> Lowering of vessel level below flange (47 hours)

<u>Window D:</u> Level flooded to 23'+ above flange (18 days not quantified)

<u>Window E:</u> Same as C, lowering of level below flange (58 hours)

<u>Window F:</u> Actual event (assessed whether shutdown risk bounded)

SDP Phase 3, Unit 2

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<u>Window A</u> (at-power, increased IE-LOOP in SPAR)

- ΔCDF = 3.6E-6/year for exposure time

<u>Windows B, C & E</u> (C-LOOP & EDG using App. G worksheets)

- ΔCDF = 2.1E-6/year for exposure time

<u>Window F</u> (Event Assessment)

- Following Appendix G guidance, potentially greater than green due to HEP dependency in LORHR sequence

<u>ΔLERF</u>

- Internal events-based screening of LERF > 1E-7/year

<u>External Events</u>

- Flooding/seismic screened
- Δ risk from fire approximated

Preliminary Results, Unit 2

- Unit 2 Total ΔCDF = **GREATER THAN GREEN**

Significance Determination Process (IMC0609): Estimated CDF (per year)			
CDF < 1E-6	**1E-6 ↔ 1E-5**	**1E-5 ↔ 1E-4**	**CDF > 1E-4**
GREEN			
VERY LOW	**WHITE**		
	LOW TO MODERATE	**YELLOW**	
		SUBSTANTIAL	**RED**
			HIGH

- Unit 2 Total ΔLERF = **GREATER THAN GREEN**

Significance Determination Process (IMC0609): Estimated LERF (per year)			
LERF < 1E-7	**1E-7 ↔ 1E-6**	**1E-6 ↔ 1E-5**	**LERF > 1E-5**
GREEN			
VERY LOW	**WHITE**		
	LOW TO MODERATE	**YELLOW**	
		SUBSTANTIAL	**RED**
			HIGH

Critical Issues

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- Un-quantified risk exists at this time
  - Unit 1 ΔCDF: SORV, LONSW, LOCCW and SLOCA
  - Unit 1 & 2 ΔLERF
  - Detailed fire contribution
- Critical assumptions
  - Frequency apportionment on single-unit vs. site-wide LOOP
  - Recoveries associated with electrical crosstie between units
- Current licensee feedback and response
  - Unit 1 Window B not yet completed
  - Unit 1 Windows C & E not fully quantified on preliminary results, but dominated by sequences not fully developed in SPAR (e.g., LOCCW, external flooding rendering the SSF non-functional, and SORV)

Offsite Power Recovery Probabilities for Plant Centere

Hour					Calculated Reovei
1	8.859284	2.976454905	0.33597015	0.802632638	2.70E-01
2	8.859284	5.952909809	0.167985075	0.627723793	1.05E-01
3	8.859284	8.929364714	0.11199005	0.543656872	6.09E-02
4	8.859284	11.90581962	0.083992537	0.490930897	4.12E-02
5	8.859284	14.88227452	0.06719403	0.45358127	3.05E-02
6	8.859284	17.85872943	0.055995025	0.425183748	2.38E-02
7	8.859284	20.83518433	0.047995736	0.402565599	1.93E-02
8	8.859284	23.81163924	0.041996269	0.383947761	1.61E-02
9	8.859284	26.78809414	0.037330017	0.368241684	1.37E-02
10	8.859284	29.76454905	0.033597015	0.354737325	1.19E-02
11	8.859284	32.74100395	0.030542741	0.342948281	1.05E-02
12	8.859284	35.71745886	0.027997512	0.332528161	9.31E-03
13	8.859284	38.69391376	0.025843858	0.323222394	8.35E-03
14	8.859284	41.67036867	0.023997868	0.314838935	7.56E-03
15	8.859284	44.64682357	0.02239801	0.307229687	6.88E-03
16	8.859284	47.62327848	0.020998134	0.300278276	6.31E-03
17	8.859284	50.59973338	0.01976295	0.293891761	5.81E-03
18	8.859284	53.57618829	0.018665008	0.28799485	5.38E-03
19	8.859284	56.55264319	0.017682639	0.282525786	5.00E-03
20	8.859284	59.52909809	0.016798507	0.277433347	4.66E-03
21	8.859284	62.505553	0.015998579	0.272674626	4.36E-03
22	8.859284	65.4820079	0.01527137	0.268213359	4.10E-03
23	8.859284	68.45846281	0.014607398	0.264018649	3.86E-03
24	8.859284	71.43491771	0.013998756	0.26006398	3.64E-03

B7

ed LOOPs

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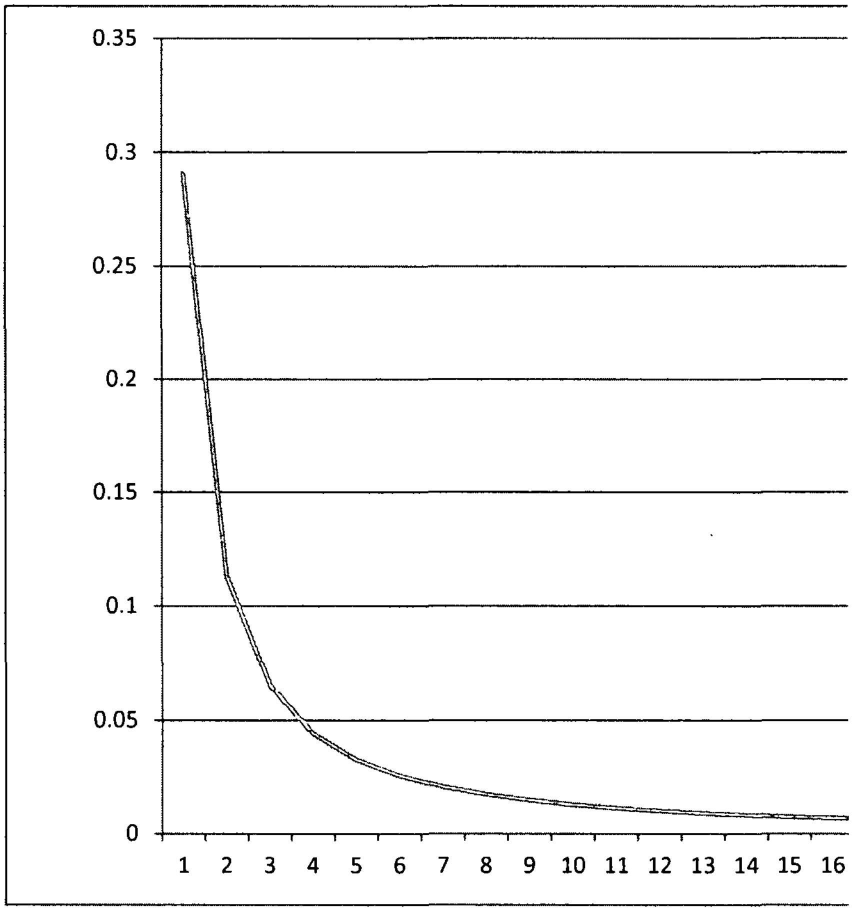

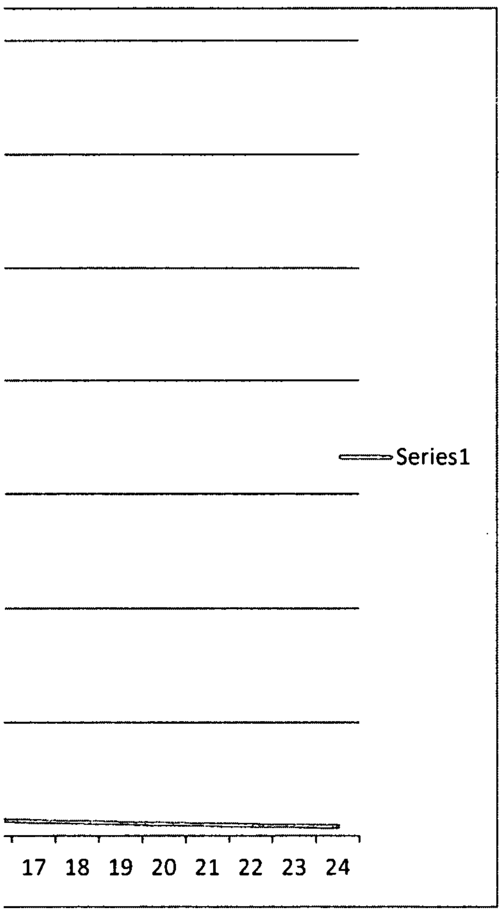
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ATTACHMENT 3 RISK RESULTS TABLE

RESULTS FOR CDF

MSLB Consequential SGTR

ECA output	MSLB Freq	Exposure	Delta CDF
4.94E-04	4.03E-04	265	1.4454E-07
SGTR ECA output		265	5.98E-08
Fire Risk		265	2.85E-08
Tornado Risk		265	1.50E-10
Seismic Risk		265	5.00E-11
	Total CDF Risk for PD		2.33E-07

RESULTS FOR LERF

CDF results less SGTR sequence 12

MSLB Consequential SGTR

ECA output	MSLB Freq	Exposure	Delta CDF
1.75E-04	4.03E-04	265	5.1203E-08
SGTR ECA output		265	1.21E-08
Fire Risk		265	2.85E-08
Tornado Risk		265	1.50E-10
Seismic Risk		265	5.00E-11
	Total LERF Risk for PD		9.20E-08

HRA Worksheets for LPSD

Plant: Initiating Event: Basic Event: Basic Event Description:

Part III - CALCULATE TASK FAILURE PROBABILITY WITHOUT FORMAL DEPENDENCY

Diagnosis HEP	+	Action HEP	=	Pw/od
1.00E-02	+	1.00E-03	=	1.10E-02

Part IV - DEPENDENCY

Condition Number	Condition selected	Crew (same or different)	Time (close in time or not close in time)	Location (same or different)	Cues (additional or no additional)	Dependency	Number of Human Action Failures Rule Not Applicable? Why?	Select Dependency
1		s	c	s	na	complete	When considering recovery in a series e.g., 2nd, 3rd, or 4th checker	
2					a	complete		
3				d	na	high		
4					a	high	If this error is the 3rd error in the sequence, then the dependency is at least **moderate**.	
5			nc	s	na	high		
6					a	moderate		
7				d	na	moderate		
8					a	low	If this error is the 4th error in the sequence, then the dependency is at least high.	
9		d	c	s	na	moderate		
10					a	moderate		
11				d	na	moderate		
12					a	moderate		
13			nc	s	na	low		
14					a	low		
15				d	na	low		
16					a	low		
17	X					zero		x

Using Pw/od = P = Task Failure Probability Without Formal Dependence:

For Complete Dependence the probability of failure = 1.0
For High Dependence the probability of failure = (1 + P)/2
For Moderate Dependence the probability of failure = (1 +6P)/7
For Low Dependence the probability of failure = (1 + 19P)/20
For Zero Dependence the probability of failure = P

Task Failure Probability With Formal Dependence = (1 + (*)) / =

Dependency **zero**

Pw/d = **1.10E-02**

Window	Start Date	End Date	Exposure (in Days)	Exposure Factor	Sequence or Event Tree	Base Case	Non-Conf.	Recovery Factor	Delta-CDF (per year)	Delta-CDF (Exp Time)	LERF Factor	delta- LERF
A	11-Jun-11	23-Jul-11	42	1.15E-01	N/A	N/A	N/A	N/A	0.00E+00	0.00E+00	N/A	0
B	23-Jul-11	05-Nov-11	105	2.88E-01	ALL	2.79E-05	1.10E-03	1.00E-02	1.07E-03	3.08E-06	0	0.00E+00
C	05-Nov-11	15-Dec-11	40	1.10E-01	TRANS	6.17E-07	8.72E-05	1	8.66E-05	9.49E-06	0	0.00E+00
	05-Nov-11	15-Dec-11	40	1.10E-01	LOACA	1.68E-05	1.68E-05	1	0.00E+00	0.00E+00	0	0.00E+00
	05-Nov-11	15-Dec-11	40	1.10E-01	LOCHS	7.53E-08	7.34E-06	1	7.26E-06	7.96E-07	0	0.00E+00
	05-Nov-11	15-Dec-11	40	1.10E-01	SGTR	3.31E-07	9.56E-06	1	9.23E-06	1.01E-06	1	1.01E-06
	05-Nov-11	15-Dec-11	40	1.10E-01	LOMFW	6.62E-08	8.62E-06	1	8.55E-06	9.37E-07	0	0.00E+00
	05-Nov-11	15-Dec-11	40	1.10E-01	LODCB	1.58E-08	1.61E-08	1	3.00E-10	3.29E-11	0	0.00E+00
	05-Nov-11	15-Dec-11	40	1.10E-01	LOIA	4.30E-09	5.73E-08	1	5.30E-08	5.81E-09	0	0.00E+00
D	15-Dec-11	21-Dec-11	6	1.64E-02	N/A	N/A	N/A	N/A	0.00E+00	0.00E+00	N/A	0
E	21-Dec-11	04-Apr-12	105	2.88E-01	TRANS	6.17E-07	8.72E-05	1	8.66E-05	2.49E-05	0	0.00E+00
	21-Dec-11	04-Apr-12	105	2.88E-01	LOACA	1.68E-05	1.68E-05	1	0.00E+00	0.00E+00	0	0.00E+00
	21-Dec-11	04-Apr-12	105	2.88E-01	LOCHS	7.53E-08	7.34E-06	1	7.26E-06	2.09E-06	0	0.00E+00
	21-Dec-11	04-Apr-12	105	2.88E-01	SGTR	3.31E-07	9.56E-06	1	9.23E-06	2.65E-06	1	2.65E-06
	21-Dec-11	04-Apr-12	105	2.88E-01	LOMFW	6.62E-08	8.62E-06	1	8.55E-06	2.46E-06	0	0.00E+00
	21-Dec-11	04-Apr-12	105	2.88E-01	LODCB	1.58E-08	1.61E-08	1	3.00E-10	8.63E-11	0	0.00E+00
	21-Dec-11	04-Apr-12	105	2.88E-01	LOIA	4.30E-09	5.73E-08	1	5.30E-08	1.52E-08	0	0.00E+00
									Total Results =	**4.75E-05**		**3.67E-06**

EVENT TIMELINE

TIME	EVENT
June 2011	Protective Relay Modification Including Zone G Installed on Unit 1. Offsite power to Unit 1 aligned from Unit 2
July 7, 2011	Unit 1 'A' train essential bus aligned to Unit 1
November 5, 2011	Unit 1 'B' train essential bus aligned to Unit 1
December 15, 2011	Unit 1 shutdown occurs without causing a LOOP
February 4, 2012	Unit 1 power aligned as supply to Unit 2 'A' train essential buses
February 18, 2012	Unit 1 power aligned as supply to Unit 2 'B' train essential bus
March 10, 2012	Unit 2 shutdown for refueling outage
April 4, 2012	Unit 1 is operating at 100%. Unit 2 is in MODE 5 with ND in service. Power to Unit 2 essential buses supplied from Unit 1
8:03 p.m.	1D NCP Y Phase cable faults to ground causing trip of 1D NCP Automatic Reactor Trip on 1D NC loop low flow Automatic Turbine Trip on Reactor Trip with power > P-8 1ATD supply to essential bus 1ETB trips deenergizing the bus
8:03:10	Generator Output breakers 1A and 1B open; 1B EDG automatically starts and repowers essential bus 1ETB
8:03:25	Generator frequency decrease below 57.9 Hz causing instantaneous underfreqency protective relay to isolate Unit 1 offsite power causing Uni1 LOOP and loss of power to Unit 2; Essential buses 1ETA, 2ETA, and 2ETB deenergize
8:03:35	1A, 2A, and 2B EDGs start and repower their essential buses; Overcurrent alarm on 2A EDG
8:06	2A ND pump started to restore decay heat removal
8:12	NOUE Declared
8:16	Initial notifications made
8:30	2B SFP cooling pump started
9:22	TSC activated
10:32	EOF activated
11:03	SSF EDG started
11:06	SSF EDG declared inoperable due to low output voltage

April 5, 1:29 a.m.	Offisite power restored to 1ETA essential bus
1:37	Offisite power restored to 2ETB essential bus; NOUE terminated
1:38	1A EDG shutdown
1:43	2B EDG shutdown
2:36	Offisite power restored to 2ETA essential bus
2:45	2A EDG shutdown
5:37	Offisite power restored to 2ETA essential bus
5:41	1B EDG shutdown
9:00	SSF EDG shutdown

Timeline of Events - Catawba Loss of Offsite Power

Date	Time	Event/Issue/Action
7/23/11		1ETA aligned back to Unit 1 SY (was aligned to Unit 2 during outage)
11/5/11		1ETB aligned back to Unit 1 SY (was aligned to Unit 2 during outage)
2/4/12	1755	2ETA aligned to Unit 1 (1TC-4)
2/18/12	1555	2ETB aligned to Unit 1 (SATB)
3/10/12	0424	Unit 2 Turbine Offline
3/10/12	1022	Unit 2 RHR in service **(POS 1)**
3/10/12	1403	2B EDG Inoperable
3/13/12	0345	Loops not filled **(POS 2)**
3/15/12	0302	Unit 2 Water Level >23 feet **(POS 3)**
3/15/12	0315	2B ND Pump Unavailable
3/15/12	0406	2B ND Pump Available
3/16/12	0345	2B ND Pump Inoperable
3/23/12	1435	2B EDG Operable
3/23/12	1549	2A EDG Inoperable (Outage tagout)
3/27/12	0511	2B ND Pump Operable
4/1/12	0848	2A EDG Operable
4/2/12	1002	Head reset **(POS 2)**
4/3/12	1036	2A EDG Inoperable (ESF testing)
4/4/12	0536	2A EDG Operable
4/4/12	1943	Unit 2 entered Mode 5
4/4/12	2003	Unit 1 reactor trip, loss of offsite power to both units. Loss of RHR and Spent Fuel Pool cooling due to loss of power. Both EDGs on both units automatically started and supplied the essential power busses.
4/4/12	2006	Started 2A RHR Pump to restore core cooling
4/4/12	2012	Unusual Event declared
4/4/12	2031	Started 2B Spent Fuel Pool Cooling Pump
4/4/12	approx 2045	Started raising Unit 2 Reactor Coolant System level. Level increased to approx 43%.
4/4/12	2122	TSC activated
4/4/12	2232	EOF activated
4/4/12	approx 2300	SSF D/G started
4/4/12	2306	SSF D/G declared inoperable due to operating at low voltage
4/5/12	0129	Offsite power restored to Unit 1 A-Train essential buss (1ETA)
4/5/12	0137	Offsite power restored to Unit 2 B-Train essential buss (2ETB)
4/5/12	0137	Unusual Event terminated
4/5/12	0138	1A EDG shutdown
4/5/12	0143	2B EDG shutdown
4/5/12	0236	Offsite power restored to Unit 2 A-Train essential buss (2ETA)
4/5/12	0245	2A EDG shutdown
4/5/12	0537	Offsite power restored to Unit 1 B-Train essential buss (1ETB)
4/5/12	0541	1B EDG shutdown
4/5/12	approx 0900	SSF D/G secured
4/5/12	approx 1200	Determined that LOOP was caused by a Zone G relay programming issue
4/5/12	1255	Started Unit 1 Condenser Circulating Water pump
4/5/12	approx 1400	Unit 2 outage schedule change to allow going to Loops Filled condition on Reactor Coolant System prior to performing B-Train ESF

Timeline of Events - Catawba Loss of Offsite Power

		testing.
4/5/12	approx 1500	Restored cooling to Unit 1 Reactor Building and Reactor Coolant Pump motors
4/5/12	approx 1600	Started the "A" Auxiliary Electric Boiler
4/5/12	1648	Started the 1A Reactor Coolant Pump
4/5/12	approx 2100	Inspected 1T1B transformed and determined no damage
4/6/12	approx 0000	Entered Unit 1 containment and checked out 1D Reactor Coolant Pump Motor. Preliminary results indicate no damage to motor.
4/6/12	approx 0200	Determined problem with SSF D/G low voltage to be caused by power factor controller not being bypassed in isochronous mode.
4/6/12	approx 0800	Established Unit 1 condenser vacuum and restored condenser dump valves to service.
4/6/12	0802	SSF motor control center (1SLXG) powered from offsite power
4/6/12	approx 0900	Restored 1B Main Power
4/8/12	0258	Loops filled **(POS 1)**

SERP Worksheet for SDP-Related Findings
Catawba Nuclear Station
Zone G Relay Modification - Unit 1 SDP

SERP Date: 07/18/2012 **EA No.:** 12-XXX

Licensee Name: Duke Energy Carolinas
Facility/Location: Catawba Nuclear Station
Docket No(s): 05000413
License No: NPF-35
Inspection Report No: 2012009
Date of Exit Meeting: June 18, 2012
Issue Sponsor: Region II
Deputy Director: Bill Jones **Division:** DRP
Branch Chief: Jonathan Bartley
Inspectors: Curt Rapp

Executive Summary:
Cornerstone Affected: □ IE ■ MS □ BI □ OR □ PR
Proposed Preliminary Results: □ White ■ Yellow □ Red □ Greater than Green
Summary of the Performance Deficiency: The licensee failed to follow the requirements of EDM 141, Procurement Specifications for Services, for providing appropriate design information to the vendor for programming the Unit 1 Zone G digital processors. Specifically, an "off-line" block for the generator underfrequency relay function was not programmed into the modification; therefore, any generator trip from high power would result in the opening of the Unit 1 switchyard breakers causing a loss of offsite power.

Summary of Significance Determination:
Provide a brief description of:
a. The Phase 1, Phase 2, and Phase 3 screening, logic process, and results

- Phase 1 - Finding represented a loss of system safety function (required Phase 2)
- Phase 2 - Finding screened as White under App. A, Table 3.7 - Loss of Offsite Power
- Phase 3 - ΔCDF = 4.7E-5, ΔLERF = 3.6E-6 (Yellow)

b. Influential Assumptions:
Window A (42 days): Both electrical buses ETA and ETB were aligned to Unit 2 supplies. If an event were to occur on Unit 1 during this time period, there would be minimal impact because both safety-related buses would maintain continuity of power. No quantification of the risk during this window was performed.
Window B (105 days): 1ETA re-aligned to a Unit 1 power supply. 1ETB aligned to Unit 2 supply. If an event were to occur on Unit 1 during this time period, the consequence of the performance deficiency would be a loss of ETA. All sequences evaluated. Recovery is not only possible, but highly likely due to the availability of the 'A' EDG and/or the cross-unit electrical feed.
Window C (40 days): Both safety-related busses being supplied from Unit 1. Any reactor trip from high power would cause the inadequate Zone G modification to divorce Unit 1 from the grid by opening up the switchyard feeder breakers. The following events/sequences were determined to cause a reactor trip and therefore needed to be evaluated: TRANS, LOACA, LOCHS, SGTR, LOMFW, LODCB, LOIA.
Window D (6 days): Both units were shutdown due to Technical Specification 3.0.3 issue with Control Room AC. No quantification of the risk during this window was performed.
Window E (105 days): Both safety-related busses being supplied from Unit 1. The risk analysis approach is identical to that of Window C.

B9

Recovery Actions: The analyst left all recovery actions at their nominal values assumed in the Catawba SPAR model. The only adjustment that was made was for recovery of the postulated failure of the ETA bus.

Standby Shutdown Facility (SSF): The SSF failed during this event but it is not being considered for the purposes of this analysis. This is because the analysis addresses only the risk of this performance deficiency, and any other PD or violation, if one is ultimately identified, will be treated separately and considered in isolation.

Ex-Core Sources: The analyst made no assessment of risk due to ex-core sources, e.g., fuel that might be damaged in the spent fuel pool due to the sustained loss of offsite power.

c. Dominant Cut-sets:

The dominant accident sequence for CDF is TRANS 21-18 and contributes 31% of the total internal events ΔCDF. The dominant accident sequence for LERF is SGTR 22-14 and contributes 69% of the total internal events ΔLERF.

d. Risk-insights:

This analysis was performed as a series of condition assessments. From the time that the performance deficiency was introduced to Unit 1 after the spring 2011 refueling outage until experienced a reactor trip and LOOP on April 4, 2012, various "risk windows" existed. The analyst identified each of these windows, determined how the performance deficiency would affect the plant, and then summed the risk for each of these windows..

e. Uncertainty and Sensitivity Studies:

Uncertainty

Upper bound for TRANS (ΔCDF) = 1.08E-4
Lower bound for TRANS (ΔCDF) = 6.4E-6
Upper bound for SGTR (ΔLERF) = 9.4E-6
Lower bound for SGTR (ΔLERF) = 6.7E-7

f. Contributions from External Events:

External Flooding - Would not cause an increase in the likelihood of a reactor trip without a LOOP. Therefore PD is present in both the base and non-conforming case.

Seismic - Same as above

Tornado - Same as above

Fire - The analyst performed a blended approach of qualitative and quantitative risk insights to demonstrate that it would not result in a change in color. Following the completion of this fire analysis, the licensee supplied risk information from their NFPA-805 transition efforts to support an estimate of the Fire Initiation Frequencies that cause a reactor trip. This number was estimated at 9E-2. Fire need not be considered any further for purposes of this analysis.

g. Potential Risk Contribution due to LERF:

NRC SPAR model for the Catawba plant did not have an ability to quantify LERF. Consequently, the analyst used the SDP Phase 2 notebooks to identify those core damage sequences that had LERF multipliers indicating that they could result in a large and prompt release to the public. Only SGTR and LOOP sequences had LERF multipliers. At the time of the completion of the analysis, the ΔLERF result was already greater-than 1E-6 (Yellow) based on the SGTR sequences and further effort was necessary to obtain the LOOP results. The analyst will continue to work to refine the estimate; also using the licensee's output from their CAFTA model to estimate LERF.

h. Total Estimated Change in Core Damage Frequency:

ΔCDF = 4.7E-5

i. Licensee's Risk Evaluation:

Comparison Between NRC and Licensee Results:

The analyst was not able to fully compare the licensee's results with the NRC results due to several factors:

- At the time of the completion of this analysis, the licensee had not yet finished their analysis of Window B and had not shared the results.
- For Windows C and E, it appeared that the TRANS scenarios that would become LOOP events

were not present in the dominant cutset results, which caused the analyst to question the completeness of the licensee's results.

- For Windows C and E, the licensee's initial results were dominated by accidents that the NRC's SPAR model was unable to quantify (e.g., LOCCW, external flooding rendering the SSF non-functional, and SORV).
- In addition, licensee concludes that in all cases, no core damage will occur with SSF available. This differs from some sequences in our model which do result in core damage. This discrepancy will need to be addressed.

j. Summary of Results and Impact:

The increase in core damage frequency (ΔCDF) for this event is 4.7×10-5 and the increase in large early release frequency (ΔLERF) for this event is 3.6×10-6, therefore, this condition should be treated as Yellow (i.e., ΔCDF greater than or equal to 10-5 and ΔLERF greater than or equal to 10-6).

Window	Start Date	End Date	Delta CDF	Delta LERF
A	11-Jun-11	23-Jul-11	0	0
B	23-Jul-11	5-Nov-11	3.08E-06	0
C	5-Nov-11	15-Dec-11	1.22E-05	1.01E-6
D	15-Dec-11	21-Dec-11	0	0
E	21-Dec-11	4-Apr-12	3.21E-05	2.65E-6
Totals =			**4.75E-05**	**3.67E-6**

Comparison Between Phase 2 and Phase 3 Results:

The SDP Phase 2 result was a White. However, there were various limitations in the ability of the Phase 2 sheets to represent the increase in risk. For example, the inspectors completed the LOOP worksheets but the PD would have resulted in a LOOP for every accident that caused a reactor trip. Also the inspectors used an IEL of zero, which was more appropriate for an event assessment as opposed to a condition assessment. And lastly, the licensee was given a recovery credit of one, which decreased the overall risk and was inappropriate especially for the short duration sequences where offsite power needed to be recovered in less than 2 hours. (Actual offsite power recovery was achieved during the event at ~ 5 hours after the LOOP.) When taken in total, these issues would explain the difference between the Phase 2 and Phase 3 results. (See Attachment 2 for details)

Summary of any Associated Apparent Violation:

Unit 1 TS 3.8.1 required in part that two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System shall be operable when operating in MODES 1, 2, 3 or 4. The TS Action Statement for Condition C required that "with two offsite circuits inoperable, restore one offsite circuit to operable status within 24 hours."

Contrary to the above, from November 5, 2011, until April 4, 2012, while the unit was in MODE 1, two offsite circuits were inoperable due to the Zone G modification error and no action was taken to restore an offsite circuit to an operable status within 24 hours.

Details

A. Summary of Issue: (include a brief description of the root cause and licensee's corrective action(s), if available):

During the Unit 1 spring 2011 refueling outage, the licensee implemented a Zone G Relay Modification. The purpose of EC 89962, Zone G Relay Modification, was to replace electromechanical and static main generator relays with multifunction, microprocessor-based relays. These relays were designed to detect faults and other abnormal conditions and isolate any element of the power system that could jeopardize the continued operation or integrity of the remainder of the system. The original design used one train of protective relays mostly arranged in a two-out-of-two scheme for each protective relaying function. The new design provided two redundant trains of relays connected in a two-out-of-two scheme for each train. One of the functions was an underfrequency relay to protect the generator by opening the switchyard breakers connected to the generator. This function allowed for the unit to be isolated from the grid while the main generator continued to power station loads in cases where the grid experiences a significant disturbance such as a load rejection.

The design requirements included an "off-line" block for the generator underfrequency relay functions. The "off-line" condition was based on the position of generator breakers 1A and 1B. If these breakers were open, the unit was considered offline and the generator underfrequency function was blocked. The licensee determined that the "off-line" block was omitted by the relay vendor for the instantaneous underfrequency relay due to a programming error. The inspectors identified that the licensee missed multiple opportunities to discover the programming error during the testing phase of the modification. These opportunities were missed mainly because the licensee did not develop testing procedures from the original design specifications. Instead, the licensee used a calculation that was generated during the vendor's design portion of the modification as the basis for the testing procedures. Consequently, the programming error propagated through the rest of the implementation phase and was undetected either at the factory or during the post modification testing (PMT). Also, the relay replacement was considered a non-QA-1 modification. Therefore, much of the additional review and rigor in the licensee's design control process was not applicable to the modification.

The licensee used relays from two different vendors to avoid common cause failure issues. One of the relays also automatically blocked the underfrequency function based on relay input voltage. If generator output was below a specific relay input voltage, these relays would block the underfrequency function for that train. Any controlled shutdown would not result in a Unit 1 LOOP because the underfrequency function was blocked based on input voltage for that train preventing the two-out-of-two logic from opening the switchyard breakers. Only in the case of a turbine trip from high power would a LOOP result because the underfrequency setpoint was reached before the automatic block could occur.

This modification was also installed on Unit 2 during the spring 2012 refueling outage. The licensee used the same vendor to program the Unit 2 relays and the same PMT procedures used on Unit 1; therefore, the programming error also was undetected on Unit 2. If Unit 2 had been restarted and operated at power then a turbine trip would have resulted in a LOOP on Unit 2. However, the LOSP on Unit 1 allowed the licensee to identify and correct the programming error on Unit 2 prior to restart.

B. Statement of the Performance Deficiency:

The licensee failed to follow the requirements of EDM 141, Procurement Specifications for Services, for providing appropriate design information to the vendor for programming the Unit 1 Zone G digital processors. Specifically, an "off-line" block for the generator underfrequency relay function was not

programmed into the modification; therefore, any generator trip from high power would result in the opening of the Unit 1 switchyard breakers causing a loss of offsite power. The PD was more than minor because it affected the availability and reliability of the Equipment Performance attribute and adversely affected the Mitigating Systems cornerstone objective in that an offsite power supply would not have been available to respond to expected operational transients.

C. Significance Determination Basis:
1. Reactor Inspection for IE, MS, BI cornerstones

a. Phase 1 screening logic:
Finding represented a loss of system safety function (requires Phase 2)

b. Phase 2 Risk Evaluation:
Finding screened as White under App. A, Table 3.7 - Loss of Offsite Power

(1) Select Phase 2 method used
□ SDP Interface (SAPHIRE Version 8) or
■ Phase 2 SDP Appendix used: __A__ (A through M)
(2) Preliminary Results: □ White ■ Yellow □ Red
(3) Provide the Phase 2 Evaluation (SDP Interface Report or SDP Appendix worksheet. (See Attached)
(4) If the preliminary risk significance determination based on Phase 2 SDP worksheet results is "Green" (1E-7) or higher significance, screen the risk contributions from external events (e.g., fire, seismic, and floods) that may add to the preliminary risk significance determination based on Phase 2 SDP worksheet results, using guidance in IMC 0609, Appendix A, Attachment 3. (See Phase 3)

c. Phase 3 Analysis:

Concisely address each of the analysis aspects that follow.
(1) The Phase 3 model revision and other PRA Tools used:
Model Used: Catawba SPAR Model Version 8.20 - Build #3 (INL model change to include offsite power recoveries for accident sequences other than LOOP)
Software Used: Saphire Version 8.0.7.17
(2) Influential Assumptions:
Window A (42 days): Both electrical buses ETA and ETB were aligned to Unit 2 supplies. If an event were to occur on Unit 1 during this time period, there would be minimal impact because both safety-related buses would maintain continuity of power. No quantification of the risk during this window was performed.
Window B (105 days): 1ETA re-aligned to a Unit 1 power supply. 1ETB aligned to Unit 2 supply. If an event were to occur on Unit 1 during this time period, the consequence of the performance deficiency would be a loss of ETA. All sequences evaluated.
Recovery is not only possible, but highly likely due to the availability of the 'A' EDG and/or the cross-unit electrical feed.
Window C (40 days): Both safety-related busses being supplied from Unit 1. Any reactor trip from high power would cause the inadequate Zone G modification to divorce Unit 1 from the grid by opening up the switchyard feeder breakers. The following events/sequences were determined to cause a reactor trip and therefore needed to be evaluated: TRANS, LOACA, LOCHS, SGTR, LOMFW, LODCB, LOIA.
Window D (6 days): Both units were shutdown due to Technical Specification 3.0.3 issue with Control Room AC. No quantification of the risk during this window was performed.
Window E (105 days): Both safety-related busses being supplied from Unit 1. The risk analysis approach is identical to that of Window C.

Recovery Actions: The analyst left all recovery actions at their nominal values assumed in the Catawba SPAR model. The only adjustment that was made was for recovery of the postulated failure of the ETA bus.
Standby Shutdown Facility (SSF): The SSF failed during this event but it is not being considered for the purposes of this analysis. This is because the analysis addresses only the risk of this performance deficiency, and any other PD or violation, if one is ultimately identified, will be treated separately and considered in isolation.
Ex-Core Sources: The analyst made no assessment of risk due to ex-core sources, e.g., fuel that might be damaged in the spent fuel pool due to the sustained loss of offsite power.

(3) Calculation Discussion (SAPHIRE analysis results, SPAR-H evaluation):
The calculations performed by the analysis included the following:
- Application of exposure time for each time window
- Calculations of ΔCDF and ΔLERF for relevant time windows
- SPAR-H calculation for EDG recovery for time window B

(4) Analysis of Dominant Cut-sets / sequences:
The dominant accident sequence for CDF is TRANS 21-18 and contributes 31% of the total internal events ΔCDF. The dominant accident sequence for LERF is SGTR 22-14 and contributes 69% of the total internal events ΔLERF. The events and important component failures in TRAN Sequence 21-18 are:
- Reactor transient (TRANS) occurs,
- Offsite electrical power fails,
- Emergency power system succeeds,
- Auxiliary feedwater (AFW) fails,
- Primary feed and bleed fails, and
- Operators fail to recover offsite power within 2 hours.

(5) Sensitivity Analysis:
(a) Contributions of greatest uncertainty factors and impact on assumptions:
See discussion of comparison between NRC and licensee results.
There may be additional recovery credit. Specifically, EDG recovery actions, LOOP recovery actions, and cross-unit recovery actions are addressed in the model; however there may be additional recovery actions to available to restore power. Those have not yet been quantified at the completion of this Phase 3 analysis.
(b) The staff should bound the uncertainties, if possible, and through sensitivity analysis (quantitative and qualitative) state why they are conservative. Bounding an assumption between two reasoned limits and selecting an average value is acceptable. The SERP will judge whether the staff's arguments are reasonable and unbiased.
The analyst qualitatively evaluated the decrease in ΔCDF due to application of the site LOOP apportionment factor and the LOOP recovery HEP. This, if applied, may decrease risk to White at the lower bound.
With respect to the upper bound, the following events either could not be evaluated for the performance deficiency of concern, or were excluded from consideration by the risk analyst: SORV, LONSW, LOCCW and SLOCA. Those events that could not be evaluated may represent un-quantified risk that may add to the total result. The analyst does not believe the risk associated with these sequences would cause an increase in color to Red.
(6) Contributions from External Events:
External Flooding - Would not cause an increase in the likelihood of a reactor trip without a LOOP. Therefore PD is present in both the base and non-conforming case.
Seismic - Same as above
Tornado - Same as above
Fire - The analyst performed a blended approach of qualitative and quantitative risk

insights to demonstrate that it would not result in a change in color. Following the completion of this fire analysis, the licensee supplied risk information from their NFPA-805 transition efforts to support an estimate of the Fire Initiation Frequencies that cause a reactor trip. This number was estimated at 9E-2. Fire need not be considered any further for purposes of this analysis.

(7) Potential Risk Contribution from LERF:

NRC SPAR model for the Catawba plant did not have an ability to quantify LERF. Consequently, the analyst used the SDP Phase 2 notebooks to identify those core damage sequences that had LERF multipliers indicating that they could result in a large and prompt release to the public. Only SGTR and LOOP sequences had LERF multipliers. At the time of the completion of the analysis, the ΔLERF result was already greater-than 1E-6 (Yellow) based on the SGTR sequences and further effort was necessary to obtain the LOOP results. The analyst will continue to work to refine the estimate; also using the licensee's output from their CAFTA model to estimate LERF.

(8) Total Estimated Change in Core Damage Frequency:

ΔCDF = 4.7E-5

(9) Licensee's Risk Evaluation:

Comparison Between NRC and Licensee Results:

The analyst was not able to fully compare the licensee's results with the NRC results due to several factors:

- At the time of the completion of this analysis, the licensee had not yet finished their analysis of Window B and had not shared the results.
- For Windows C and E, it appeared that the TRANS scenarios that would become LOOP events were not present in the dominant cutset results, which caused the analyst to question the completeness of the licensee's results.
- For Windows C and E, the licensee's initial results were dominated by accidents that the NRC's SPAR model was unable to quantify (e.g., LOCCW, external flooding rendering the SSF non-functional, and SORV).
- In addition, licensee concludes that in all cases, no core damage will occur with SSF available. This differs from some sequences in our model which do result in core damage. This discrepancy will need to be addressed.

(10) Summary of Results and Impact:

The increase in core damage frequency (ΔCDF) for this event is 4.7×10^{-5} and the increase in large early release frequency (ΔLERF) for this event is 3.6×10^{-6}, therefore, this condition should be treated as Yellow (i.e., ΔCDF greater than or equal to 10^{-5} and ΔLERF greater than or equal to 10^{-6}).

Window	Start Date	End Date	Delta CDF	Delta LERF
A	11-Jun-11	23-Jul-11	0	0
B	23-Jul-11	5-Nov-11	3.08E-06	0
C	5-Nov-11	15-Dec-11	1.22E-05	1.01E-6
D	15-Dec-11	21-Dec-11	0	0
E	21-Dec-11	4-Apr-12	3.21E-05	2.65E-6
Totals =			**4.75E-05**	**3.67E-6**

Comparison Between Phase 2 and Phase 3 Results:

The SDP Phase 2 result was a White. However, there were various limitations in the ability of the Phase 2 sheets to represent the increase in risk. For example, the inspectors completed the LOOP worksheets but the PD would have resulted in a LOOP for every accident that caused a reactor trip. Also the inspectors used an IEL of zero, which was more appropriate for an event assessment as opposed to a condition assessment. And lastly, the licensee was given a recovery credit of one, which decreased the overall risk and was inappropriate especially for the short duration sequences where offsite power needed to be recovered in less than 2 hours. (Actual

offsite power recovery was achieved during the event at ~ 5 hours after the LOOP.) When taken in total, these issues would explain the difference between the Phase 2 and Phase 3 results. (See Attachment 2 for details)

d. Peer Review: George MacDonald

Summarize any unresolved issues identified by the reviewer.

N/A

e. References: (See Phase 3)

2. All Other Inspection Findings (not IE, MS, BI cornerstones)

Flowchart logic and full justification of assumptions used: N/A

Proposed preliminary or final color: N/A

D. Proposed Enforcement:

1. Regulatory requirement not met: TS 3.8.1

2. Proposed citation:

Unit 1 TS 3.8.1 required in part that two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System shall be operable when operating in MODES 1, 2, 3 or 4. The TS Action Statement for Condition C required that "with two offsite circuits inoperable, restore one offsite circuit to operable status within 24 hours."

Contrary to the above, from November 5, 2011, until April 4, 2012, while the unit was in MODE 1, two offsite circuits were inoperable due to the Zone G modification error and no action was taken to restore an offsite circuit to an operable status within 24 hours.

E. Determination of Follow-up Review:

For White findings propose whether headquarters (NRR and/or OE) should review final determination letter before issuance. (For greater than White findings, review and concurrence by NRR and OE is required as discussed in Section 4b.)

Review and concurrence by NRR and OE

SERP Worksheet for SDP-Related Findings
Catawba Nuclear Station
Zone G Relay Modification - Unit 2 SDP

SERP Date: 07/18/2012 **EA No.:** 12-XXX

Licensee Name: Duke Energy Carolinas
Facility/Location: Catawba Nuclear Station
Docket No(s): 05000414
License No: NPF-52
Inspection Report No: 2012009
Date of Exit Meeting: June 18, 2012
Issue Sponsor: Region II
Deputy Director: Bill Jones **Division:** DRP
Branch Chief: Jonathan Bartley
Inspectors: Curt Rapp

Executive Summary:
Cornerstone Affected: □ IE ■ MS □ BI □ OR □ PR
Proposed Preliminary Results: □ White □ Yellow □ Red ■ Greater than Green
Summary of the Performance Deficiency: The licensee failed to follow the requirements of EDM 141, Procurement Specifications for Services, for providing appropriate design information to the vendor for programming the Unit 1 Zone G digital processors. Specifically, an "off-line" block for the generator underfrequency relay function was not programmed into the modification; therefore, any generator trip from high power would result in the opening of the Unit 1 switchyard breakers causing a loss of offsite power. This would cause a loss of offsite power to Unit 2 because Unit 1 was aligned to provide offsite power to Unit 2.

Summary of Significance Determination:
Provide a brief description of:

a. The Phase 1, Phase 2, and Phase 3 screening, logic process, and results:

- Phase 1 - Finding represented a loss of system safety function (required Phase 2)
- Phase 2 -
  - Finding screened as Green under App. A, Table 3.7 - LOOP (at-power)
  - Finding screened as >Green under Appendix G, Worksheet 3 - PWR/LOOP (shutdown)
- Phase 3 - Finding resulted in ΔCDF of 4.11E-6, LERF uncertainty (Greater than Green)

b. Influential Assumptions:

Window A (At Power) (21 days): Only LOOP sequences were evaluated since any other event that originated in Unit 2 (e.g., LOMFW, TRANS) would progress normally.
Window B (POS1 TW-E) (64 hours): Both trains of RHR available for heat removal, RCS was filled and vented and the steam generators available, and 2B EDG was out-of-service for extensive maintenance. Plant-centered and/or switchyard-centered LOOP was credible. A weather-related or grid related LOOP was not considered
Window B (POS2 TW-E) (47 hours): Mode 6, reactor vessel (RV) level lowered below the flange for RV head removal, and both trains of RHR available. Plant-centered and/or switchyard-centered LOOP was credible. A weather-related or grid related LOOP was not considered
Window C (POS3) (18 days): Risk not evaluated because the potential loss of off-site or on-site emergency power was determined to be of low risk significance due to the high amount of inventory and/or recovery time available.
Window D (POS2 TW-L) (58 hours): Mode 6 and Mode 5, RV level lowered below the flange for RV head reinstallation, both trains of RHR available, and 2A EDG out-of-service
Window E (Actual Event): Plant conditions were identical to Window D, however the analyst

B10

evaluated the risk of the event by treating it as a precursor event.

c. Dominant Cut-sets:

The dominant accident sequence is a LOOP 19-02 during the At-Power window and contributes 92% of the total internal events ΔCDF.

d. Risk-insights:

The performance deficiency was identified as a result of the LOOP event on April 4, 2012. The condition potentially affected Unit 2 due to the crosstie of electrical power and therefore affected various plant modes and operational states. An approximation of the risk in the various shutdown conditions was obtained via the SDP Appendix G worksheets. Then the model was used for the analysis of the operating condition (Appendix A) to generate a ΔCDF and the results were summed. The event starts as a LOOP that affects both units with failure of both diesels and non-recovery of offsite power.

e. Uncertainty and Sensitivity Studies:

The analyst was unable to perform uncertainty calculations due to problems with the model. <u>Window A</u>: As a sensitivity study, the analyst modified the offsite power recoveries at certain time periods (OEP-XHE-XL-NR02H, NR04H, and NR24H) due to their significance in the base case. This was an attempt to ensure that if somewhat more optimistic estimates were used for the offsite power recoveries, such as those in the McGuire SPAR model, that there would not be a significant change in the result. The non-conforming case in this scenario decreased from 7.43E-5 to 3.9E-5 and did not result in a color change.

f. Contributions from External Events:

<u>External Flooding</u> - Would not cause an increase in the likelihood of a reactor trip without a LOOP. Therefore PD is present in both the base and non-conforming case.

<u>Seismic</u> - Same as above

<u>Tornado</u> - Same as above

<u>Fire</u> - At the time of the completion of this analysis, the licensee had not supplied any risk information from their NFPA-805 transition efforts to support a detailed estimate of the Fire Initiation Frequencies that cause a reactor trip. However, the analyst performed a blended approach of qualitative and quantitative risk insights to demonstrate that it would not result in a change in color.

g. Potential Risk Contribution due to LERF:

NRC SPAR model did not have an ability to quantify LERF. Consequently, the analyst used the internal events CDF result and applied several "screenings" to determine those accident sequences that would contribute to LERF risk. The analyst filtered the SPAR model results for cutsets that involved failure to recover offsite power at the 1 hour and 2 hour timeframes, since these would constitute an event that rapidly evolved. Further screening was applied in order to consider only those sequences where both EDGs failed (i.e., SBO) and the TDAFW also failed (likely a high pressure sequence). The aforementioned sequences when quantified appeared to be greater than 1E-7 so were potentially White or higher on LERF.

h. Total Estimated Change in Core Damage Frequency:

4.11E-6

i. Licensee's Risk Evaluation:

<u>Comparison Between NRC and Licensee Results:</u>

At the time of completion of this analysis, the licensee had not yet provided their risk results. However, through discussions with Duke PRA personnel, the analyst determined that two of the significant differences between the NRC results and licensee results were:

- The apportionment factor used in the respective models, representing those LOOPs that are or become site-wide and affect both units. The NRC uses a value of 5.7E-1 whereas the licensee uses a value of 1.6E-1.
- The HEP associated with electrically cross-connecting the units is assumed to be 1E-1, whereas the licensee assumes 4.3E-2.

When taken together, if used, these factors would impact the NRC results and may result in a significant reduction in the risk estimate.

In addition, licensee concludes that in all cases, no core damage will occur with SSF available. This differs from some sequences in our model which do result in core damage. This discrepancy will need to be addressed.

j. Summary of Results and Impact:

Window	Individual Risk Results
A (At-Power)	3.8E-6
B (Shutdown – POS-1)	6.7E-9
C (Shutdown – POS-2)	1.43E-7
D (Shutdown – POS-3)	0
E (Shutdown – POS-2)	1.74E-7
F (Shutdown – Precursor Event)	1.4E-7
Total Result =	**4.11E-6**

Comparison Between Phase 2 and Phase 3 Results:
The Phase 2 results initially calculated by the inspectors for the At-Power window underestimated the risk because the LOOP frequency was not increased sufficiently and additional recovery credit was applied. The Phase 1 results for the Shutdown windows were initially much higher than the actual risk due to lack of refinement in the LOOP frequencies and the credit for EAC. No further reconciliation with the Phase 2 results is necessary.

Summary of any Associated Apparent Violation:
Unit 2 TS 3.8.1 required in part that two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System shall be operable when operating in MODES 1, 2, 3 or 4. The TS Action Statement for Condition C required that "with two offsite circuits inoperable, restore one offsite circuit to operable status within 24 hours." Unit 2 TS 3.8.2 required in part that one qualified circuit between the offsite transmission network and the Onsite Essential Auxiliary Power distribution system shall be operable when operating in MODES 5, 6, and during movement of irradiated fuel assemblies. The TS Action Statement for Condition A required that "with one required offsite circuit inoperable, initiate action to restore required offsite power circuit to operable status immediately."

Contrary to the above, from February 18, 2012, until March 10, 2012, while the unit was operating in MODES 1-4, two offsite circuits were inoperable due to the Zone G modification error and no action was taken to restore an offsite circuit to an operable status within 24 hours. In addition, from March 10, 2012, until April 4, 2012, while the unit was operating in MODES 5-6, one offsite circuit was inoperable due to the Zone G modification error and no immediate action was taken to restore the circuit to an operable status.

Details

A. Summary of Issue: (include a brief description of the root cause and licensee's corrective action(s), if available):

During the Unit 1 spring 2011 refueling outage, the licensee implemented a Zone G Relay Modification. The purpose of EC 89962, Zone G Relay Modification, was to replace electromechanical and static main generator relays with multifunction, microprocessor-based relays. These relays were designed to detect faults and other abnormal conditions and isolate any element of the power system that could jeopardize the continued operation or integrity of the remainder of the system. The original design used one train of protective relays mostly arranged in a two-out-of-two scheme for each protective relaying function. The new design provided two redundant trains of relays connected in a two-out-of-two scheme for each train. One of the functions was an underfrequency relay to protect the generator by opening the switchyard breakers connected to the generator. This function allowed for the unit to be isolated from the grid while the main generator continued to power station loads in cases where the grid experiences a significant disturbance such as a load rejection.

The design requirements included an "off-line" block for the generator underfrequency relay functions. The "off-line" condition was based on the position of generator breakers 1A and 1B. If these breakers were open, the unit was considered offline and the generator underfrequency function was blocked. The licensee determined that the "off-line" block was omitted by the relay vendor for the instantaneous underfrequency relay due to a programming error. The inspectors identified that the licensee missed multiple opportunities to discover the programming error during the testing phase of the modification. These opportunities were missed mainly because the licensee did not develop testing procedures from the original design specifications. Instead, the licensee used a calculation that was generated during the vendor's design portion of the modification as the basis for the testing procedures. Consequently, the programming error propagated through the rest of the implementation phase and was undetected either at the factory or during the post modification testing (PMT). Also, the relay replacement was considered a non-QA-1 modification. Therefore, much of the additional review and rigor in the licensee's design control process was not applicable to the modification.

The licensee used relays from two different vendors to avoid common cause failure issues. One of the relays also automatically blocked the underfrequency function based on relay input voltage. If generator output was below a specific relay input voltage, these relays would block the underfrequency function for that train. Any controlled shutdown would not result in a Unit 1 LOOP because the underfrequency function was blocked based on input voltage for that train preventing the two-out-of-two logic from opening the switchyard breakers. Only in the case of a turbine trip from high power would a LOOP result because the underfrequency setpoint was reached before the automatic block could occur.

This modification was also installed on Unit 2 during the spring 2012 refueling outage. The licensee used the same vendor to program the Unit 2 relays and the same PMT procedures used on Unit 1; therefore, the programming error also was undetected on Unit 2. If Unit 2 had been restarted and operated at power then a turbine trip would have resulted in a LOOP on Unit 2. However, the LOSP on Unit 1 allowed the licensee to identify and correct the programming error on Unit 2 prior to restart.

B. Statement of the Performance Deficiency:

The licensee failed to follow the requirements of EDM 141, Procurement Specifications for Services, for providing appropriate design information to the vendor for programming the Unit 1 Zone G digital processors. Specifically, an "off-line" block for the generator underfrequency relay function was not

programmed into the modification; therefore, any generator trip from high power would result in the opening of the Unit 1 switchyard breakers causing a loss of offsite power. This would cause a loss of offsite power to Unit 2 because Unit 1 was aligned to provide offsite power to Unit 2. The PD was more than minor because it affected the availability and reliability of the Equipment Performance attribute and adversely affected the Mitigating Systems cornerstone objective in that an offsite power supply would not have been available to respond to expected operational transients.

C. Significance Determination Basis:

1. Reactor Inspection for IE, MS, BI cornerstones

a. Phase 1 screening logic:

Finding represented a loss of system safety function (requires Phase 2)

b. Phase 2 Risk Evaluation:

Finding screened as Green under App. A, Table 3.7 - LOOP (at-power)
Finding screened as >Green under Appendix G, Worksheet 3 - PWR/LOOP (shutdown)

(1) Select Phase 2 method used

□ SDP Interface (SAPHIRE Version 8) or
■ Phase 2 SDP Appendix used: A and G (A through M)

(2) Preliminary Results: □ White □ Yellow □ Red ■ Greater than Green

(3) Provide the Phase 2 Evaluation (SDP Interface Report or SDP Appendix worksheet. (See Attached)

(4) If the preliminary risk significance determination based on Phase 2 SDP worksheet results is "Green" (1E-7) or higher significance, screen the risk contributions from external events (e.g., fire, seismic, and floods) that may add to the preliminary risk significance determination based on Phase 2 SDP worksheet results, using guidance in IMC 0609, Appendix A, Attachment 3. (See Phase 3)

c. Phase 3 Analysis:

Concisely address each of the analysis aspects that follow.

(1) The Phase 3 model revision and other PRA Tools used:

Model Used: Catawba SPAR Model Version 8.20
Software Used: Saphire Version 8.0.7.17

(2) Influential Assumptions:

The inadequately designed modification to the Unit 2 switchyard was in the process of being installed during the spring 2012 outage, when the LOOP event occurred. The increased risk to Unit 2 was due to Unit 1 modification to the Zone G protective relaying logic combined with the plant's procedure to cross-connect the safety-related electrical power during an outage. On February 4, 2012, the electrical bus 2ETA was aligned to Unit 1. On March 18, 2012, the electrical bus 2ETB was aligned to Unit 1 at that point thereby exposing Unit 2 to the increased risk because both trains were cross connected. On March 10, 2012, Unit 2 shutdown for a refueling outage, thus ending the at-power exposure period (19 days). On April 4, 2012, the LOOP occurred as a result of the Unit 1 reactor trip and turbine trip, which ended the shutdown exposure period (25 days total). The full exposure time (T) was used. Please refer to Attachment 9 for a simplified diagram of the exposure windows.

(3) Calculation Discussion (SAPHIRE analysis results, SPAR-H evaluation):

The calculations performed by the analysis included the following:

- Application of exposure time for each time window
- Modified shutdown Phase 2 calculations for the CCDP estimates for each window

- SPAR-H calculation for EDG recovery for time window F

(4) Analysis of Dominant Cut-sets / sequences:

The dominant accident sequence is a LOOP 19-02 during the At-Power window and contributes 92% of the total internal events ΔCDF. The events and important component failures in the at-power sequence are:

Loss of offsite power (LOOP) transient occurs due to the performance deficiency,

- Emergency AC Power fails from both EDGs
- Auxiliary Feedwater succeeds
- PORVs/SRVs remain closed during the event
- Standby Shutdown Facility cooling to the RCP seals succeeds
- Failure to recover offsite power in 2 hours, leading to core damage

(5) Sensitivity Analysis:

(a) Contributions of greatest uncertainty factors and impact on assumptions:

See discussion of comparison between NRC and licensee results.

There may be additional recovery credit. Specifically, EDG recovery actions, LOOP recovery actions, and cross-unit recovery actions are addressed in the model; however there may be additional recovery actions to available to restore power. Those have not yet been quantified at the completion of this Phase 3 analysis.

(b) The staff should bound the uncertainties, if possible, and through sensitivity analysis (quantitative and qualitative) state why they are conservative. Bounding an assumption between two reasoned limits and selecting an average value is acceptable. The SERP will judge whether the staff's arguments are reasonable and unbiased.

The analyst qualitatively evaluated the decrease in ΔCDF due to application of the site LOOP apportionment factor and the LOOP recovery HEP. If applied, the risk may decrease to a high E-7 result.

Analyst attempted to determine the upper bound for this analysis by taking all LOOP sequences in the results and applying a 1.0 LERF multiplier with a result of ΔLERF 2.8E-6 (Yellow for LERF). This would be overly conservative since only some LOOP sequences are high pressure and LERF multipliers may be less than 1.0.

(6) Contributions from External Events:

<u>External Flooding</u> - Would not cause an increase in the likelihood of a reactor trip without a LOOP. Therefore PD is present in both the base and non-conforming case.

<u>Seismic</u> - Same as above

<u>Tornado</u> - Same as above

<u>Fire</u> - At the time of the completion of this analysis, the licensee had not supplied any risk information from their NFPA-805 transition efforts to support a detailed estimate of the Fire Initiation Frequencies that cause a reactor trip. However, the analyst performed a blended approach of qualitative and quantitative risk insights to demonstrate that it would not result in a change in color.

(7) Potential Risk Contribution from LERF:

NRC SPAR model did not have an ability to quantify LERF. Consequently, the analyst used the internal events CDF result and applied several "screenings" to determine those accident sequences that would contribute to LERF risk. The analyst filtered the SPAR model results for cutsets that involved failure to recover offsite power at the 1 hour and 2 hour timeframes, since these would constitute an event that rapidly evolved. Further screening was applied in order to consider only those sequences where both EDGs failed (i.e., SBO) and the TDAFW also failed (likely a high pressure sequence). The aforementioned sequences when quantified appeared to be greater than 1E-7 so were potentially White or higher on LERF. Further work is needed to refine this number.

(8) Total Estimated Change in Core Damage Frequency:

4.11E-6

(9) Licensee's Risk Evaluation:

Comparison Between NRC and Licensee Results:
At the time of completion of this analysis, the licensee had not yet provided their risk results. However, through discussions with Duke PRA personnel, the analyst determined that two of the significant differences between the NRC results and licensee results were:

- The apportionment factor used in the respective models, representing those LOOPs that are or become site-wide and affect both units. The NRC uses a value of 5.7E-1 whereas the licensee uses a value of 1.6E-1.
- The HEP associated with electrically cross connecting the units is assumed to be 1E-1, whereas the licensee assumes 4.3E-2.

When taken together, if used, these factors would impact the NRC results and may result in a significant reduction in the risk estimate.
In addition, licensee concludes that in all cases, no core damage will occur with SSF available. This differs from some sequences in our model which do result in core damage. This discrepancy will need to be addressed.

(10) Summary of Results and Impact:
Summation of Results:

Window	Individual Risk Results
A (At-Power)	3.8E-6
B (Shutdown – POS-1)	6.7E-9
C (Shutdown – POS-2)	1.43E-7
D (Shutdown – POS-3)	0
E (Shutdown – POS-2)	1.74E-7
F (Shutdown – Precursor Event)	1.4E-7
Total Result =	**4.11E-6**

Comparison Between Phase 2 and Phase 3 Results:
The Phase 2 results initially calculated by the inspectors for the At-Power window underestimated the risk because the LOOP frequency was not increased sufficiently and additional recovery credit was applied. The Phase 1 results for the Shutdown windows were initially much higher than the actual risk due to lack of refinement in the LOOP frequencies and the credit for EAC. No further reconciliation with the Phase 2 results is necessary.

d. Peer Review: Rudy Bernhard
Summarize any unresolved issues identified by the reviewer.
N/A

e. References: (See Phase 3)

2. All Other Inspection Findings (not IE, MS, BI cornerstones)

Flowchart logic and full justification of assumptions used: N/A

Proposed preliminary or final color: N/A

D. Proposed Enforcement:

1. Regulatory requirement not met: TS 3.8.1 and TS 3.8.2

2. Proposed citation:
Unit 2 TS 3.8.1 required in part that two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System shall be operable when operating in MODES 1, 2, 3 or 4. The TS Action Statement for Condition C required that "with two offsite

circuits inoperable, restore one offsite circuit to operable status within 24 hours." Unit 2 TS 3.8.2 required in part that one qualified circuit between the offsite transmission network and the Onsite Essential Auxiliary Power distribution system shall be operable when operating in MODES 5, 6, and during movement of irradiated fuel assemblies. The TS Action Statement for Condition A required that "with one required offsite circuit inoperable, initiate action to restore required offsite power circuit to operable status immediately."

Contrary to the above, from February 18, 2012, until March 10, 2012, while the unit was operating in MODES 1-4, two offsite circuits were inoperable due to the Zone G modification error and no action was taken to restore an offsite circuit to an operable status within 24 hours. In addition, from March 10, 2012, until April 4, 2012, while the unit was operating in MODES 5-6, one offsite circuit was inoperable due to the Zone G modification error and no immediate action was taken to restore the circuit to an operable status.

E. Determination of Follow-up Review (as needed)

For White findings propose whether headquarters (NRR and/or OE) should review final determination letter before issuance. (For greater than White findings, review and concurrence by NRR and OE is required as discussed in Section 4b.)

Review and concurrence by NRR and OE if final determination is greater than White

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400

350

300

20

250

200

150

950
RPV Wall Temp A
Bottom Head Drain
Loop B RCR
Loop A RCR
RPV Pressure

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850
800
750
700
650
600
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Table 1- SDP PHASE 1 SCREENING WORKSHEET FOR ALL CORNERSTONES
Reference/Title (LER #, Inspection Report #, etc): 05000413/2012009, 05000414/2012009
Performance Deficiency (concise statement clearly stating deficient licensee performance): The licensee failed to follow the requirements of EDM 141 for providing appropriate design information to the vendor for programming the Zone G digital processors.
Factual Description of Condition (statement of <u>facts</u> known about the condition that resulted from the performance deficiency, <u>without</u> hypothetical failures included.) Explain why issue is more than minor: Unit 2 was cross-tied through Unit 1 during the Unit 2 outage to meet the requirement for one circuit of offsite power. Due to the Zone G modification performed on Unit 1, Unit 2 was susceptible to a loss of offsite power for any event or transient on Unit 1 from 100% power which resulted in a reactor/turbine trip.
System(s)/Train(s) Degraded by Condition or Programmatic Weakness (note that the safety functions affected must be those identified in the Site Specific Risk-Informed Inspection Notebooks): Offsite Power - Consisting of one qualified circuit between the offsite transmission network and the Onsite Essential Auxiliary Power System, during MODE 5, MODE 6, and movement of irradiated fuel.
Licensing Basis Function of System(s)/Train(s) or Program: An offsite power system and an onsite power system are provided for each unit at the Catawba Nuclear Station to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safety Features Systems during abnormal and accident conditions. Each Catawba Unit is connected to a common 230kV switchyard and thereby to the Duke 230kV transmission system via two separate and independent transmission lines.
Other Safety Function of System(s)/Train(s): N/A
Maintenance Rule Category (check one): _X_ risk-significant ____ non risk-significant
Time condition existed or is assumed to have existed: Condition existed from February 4, 2012, when 2ETA was cross-tied through Unit 1 for offsite power, until April 4, 2012, when the event occurred. (Unit 2 shutdown for refueling outage on March 10, 2012)

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Table 2 - CORNERSTONES AND FUNCTIONS DEGRADED AS A RESULT OF DEFICIENCY
(✔) Check the appropriate boxes

INITIATING EVENTS CORNERSTONE	MITIGATION SYSTEMS CORNERSTONE	BARRIERS CORNERSTONE
☐ Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ☐ Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ☐ Fire initiator contributor (e.g., transient loadings and combustibles, hotwork) ☐ Internal/external flooding initiator contributor	☒ Core Decay Heat Removal Degraded ☒ Short Term Heat Removal Degraded ☒ Primary (e.g., Safety Inj, [main feedwater, HPCI, and RCIC - BWR only]) _X_ High Pressure _X_ Low Pressure ☐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ☐ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ☐ Reactivity Control Degraded ☐ Seismic/Fire/Flood/Severe Weather Protection Degraded	☐ RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). Note: all other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. ☐ Containment Barrier Degraded ☐ Reactor Containment Degraded ___ Actual Breach or Bypass ___ Heat Removal, Hydrogen or Pressure Control Degraded ☐ Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ☐ Fuel Cladding Barrier Degraded ☐ Spent Fuel Pool ☐ Spent Fuel Pool Boiling ☐ Fuel Handling ☐ Spent Fuel Pool Inventory
EMERGENCY PREPAREDNESS CORNERSTONE	**OCCUPATION RADIATION SAFETY CORNERSTONE**	**PUBLIC RADIATION SAFETY CORNERSTONE**
☐ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard ☐ Actual Event Implementation Problem	☐ ALARA Planning or Work Controls ☐ Exposure or Over-exposure problem ☐ Ability to Assess Dose Compromised	☐ Radioactive Effluent Release Program ☐ Radioactive Environmental Monitoring Program ☐ Radioactive Material Control Program ☐ Transportation or Part 61
SECURITY CORNERSTONE		
☐ Findings identified under the IMC-2201, Security and Safeguards Inspection Program		

Table 3a - SDP PHASE 1 SCREENING WORKSHEET FOR EMERGENCY PREPAREDNESS, OCCUPATIONAL & PUBLIC RADIATION, AND SECURITY CORNERSTONES
IF the finding is in the licensee's: 1. emergency preparedness area, **THEN STOP. Go to** IMC 0609, Appendix B. 2. occupational radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix C. 3. public radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix D. 4. security area, **THEN STOP. Go to** IMC 0609, Appendix E.

Table 3b - SDP PHASE 1 SCREENING WORKSHEET FOR INITIATING EVENTS, MITIGATION SYSTEMS, AND BARRIERS CORNERSTONES
IF the finding affects: 1. fire protection defense-in-depth strategies involving: detection, suppression (equipment for both manual and automatic), barriers, fire prevention and administrative controls, and post fire safe shutdown systems, **THEN STOP. Go to** IMC 0609, Appendix F. Issues related to performance of the fire brigade are not included in Appendix F and require NRC management review using Appendix M. x 2. the safety of a reactor during refueling outages, forced outages, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated, **THEN STOP. Go to** IMC 0609, Appendix G. 3. the operator licensing requalification program or simulator fidelity, **THEN STOP. Go to** IMC 0609, Appendix I. 4. steam generator tube integrity, **THEN STOP. Go to** IMC 0609, Appendix J. 5. the licensee's assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control," **THEN STOP. Go to** IMC 0609, Appendix K. 6. SSCs where existing SDP guidance is not adequate to provide reasonable estimates of the findings significance within the established SDP timeliness goal of 90 days, **THEN STOP. Go to** IMC 0609, Appendix M. 7. the safety of an operating reactor, **THEN IDENTIFY** the degraded cornerstone(s): ☐ Initiating Event ☐ Mitigation Systems ☐ RCS Barrier (e.g., PTS issues) ☐ Fuel Barrier ☐ Containment Barriers **CONTINUE** to the appropriate column in Table 4a - Characterization Worksheet. NOTE: When assessing the significance of a finding affecting multiple cornerstones, the finding should be assigned to the cornerstone that best reflects the dominant risk of the finding.

Initiating Event Data Sheets

Update 2010

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3:2

Update Notes

This file represents the first update to the original set of initiating event data sheets, which was completed in February 2007. The original set of initiating event data sheets were extracted from NUREG/CR-6928 [Reference 4] and generally contained data from the date range of 1988 to 2002. This file generally represents availability results using a date range of 1988 to 2010.

This update is different from the original in the following respects:

1. The hierarchy of the report has been changed to facilitate finding sections
2. Several new initiating events have been added to support more detailed SPAR models.
    a. All of the high-energy line break events
    b. Two or more stuck open relief valves
    c. Calculated loss of multiple AC or DC busses
    d. Interfacing system Loss of Coolant Accident (LOCA)
    e. Reactor Coolant Pump Seal LOCA (RCPLOCA)

The date of each initiating event sheet is in the footer of the initiating event data sheet. Some of the initiating event data sheets have not been updated since the original NUREG/CR-6928 since the particular piece of data is not maintained and have February 2007 in the footer.

The original NUREG/CR-6928 used some statistical adjustments to data that have been modified to be less arbitrary:

1. The use of the SCNID distribution (a simplified version of the CNID) has been discontinued. The Jefferies update replaces that distribution. The SCNID had the property of producing a result with a highly uncertain distribution, which was supposed to enhance the use of the reliability results as the prior to a plant-specific update. The primary use of these results is to support SPAR modeling, and the use of highly uncertain distributions leads to more uncertainty in the final CDF.
2. There was a decision made when the empirical Bayes (EB) analysis produced a result that had a low (<0.3) α parameter to the beta or gamma distribution, that the α parameter was reset to 0.3 and β and the mean were recalculated. This action was motivated since the EB could produce extremely wide distributions that nobody believed were valid. This update revises the decision-making and the alternative method of obtaining a reasonable distribution. The decision point is now whether the difference between the 5^{th} percentile and the mean is greater than 4 orders of magnitude (this happens to approximate the decision point of $\alpha < 0.3$). When the decision point is reached, instead of creating an arbitrary distribution, the Jeffries distribution is used, which is the same decision that is made when the EB does not return a result.

No significant differences from the current estimates to the estimates in NUREG/CR-6928 were noted.

1 High Energy Line Breaks

This category includes breaks of steam and feedwater lines greater than one inch in diameter. It does not have to be a complete break. Included are actuations or failure of rupture disks, splits, cracks, and failed welds.

1.1 Feedwater Line Break (BWR)

1.1.1 Initiating Event Description

From Reference 3, the Feedwater Line Break at Pressurized Water Reactors (FWLB (BWR)) initiating event is a break of a one-inch equivalent diameter or more in a feedwater or condensate line that contains main turbine working fluid at or above atmospheric saturation conditions. Examples include: breeches of a pipe caused by a split, crack, weld failure, or circumferential break.

1.1.2 Data Collection and Review

Data for the FWLB (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for FWLB (BWR) is 1988–2010. Figure 1-1 shows the trend of the full FWLB (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the FWLB (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry.

Table 1-1 summarizes the data obtained from RADS and used in the FWLB (BWR) analysis.

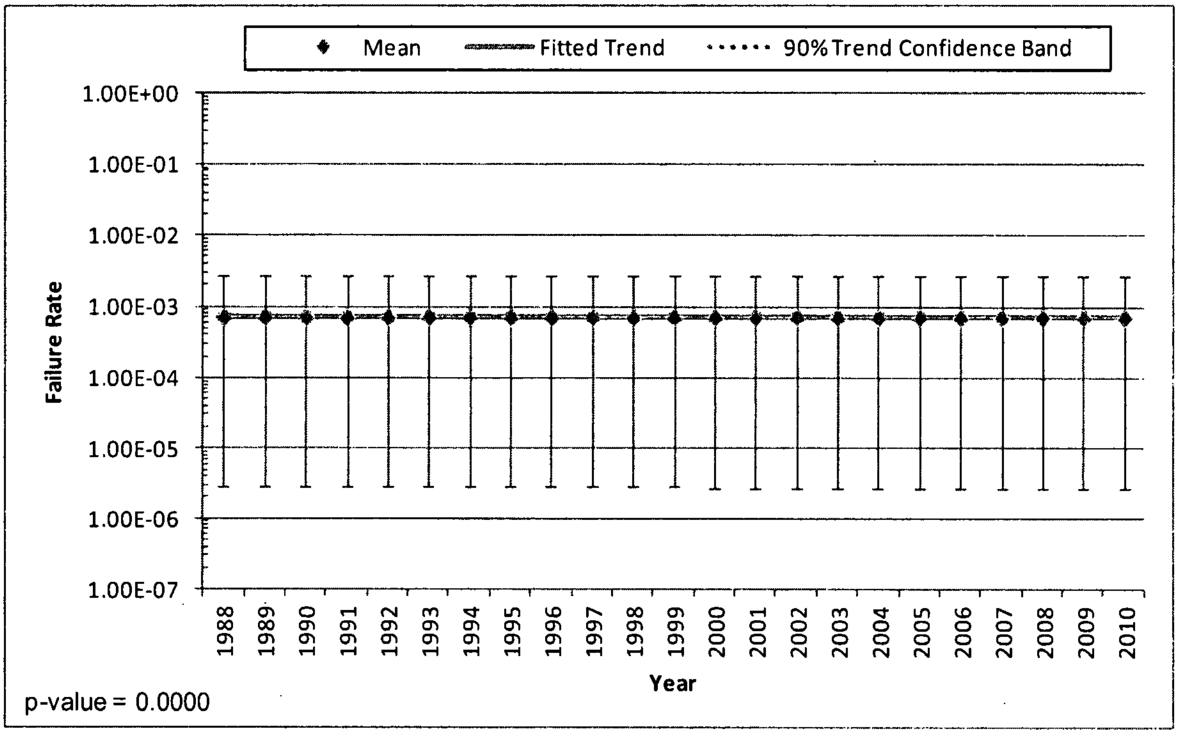

Figure 1-1. FWLB (BWR) trend plot.

Table 1-1. FWLB (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	672.9	1988-2010	38	0.0%

1.1.3 Industry-Average Baselines

Table 1-2 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 1-2. Selected industry distribution of λ for FWLB (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	2.92E-06	3.38E-04	7.43E-04	2.85E-03	Gamma	0.500	6.729E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

1.2 Feedwater Line Break (PWR)

1.2.1 Initiating Event Description

From Reference 3, the Feedwater Line Break at Pressurized Water Reactors (FWLB (PWR)) initiating event is a break of a one-inch equivalent diameter or more in a feedwater or condensate line that contains main turbine working fluid at or above atmospheric saturation conditions. Examples include: breeches of a pipe caused by a split, crack, weld failure, or circumferential break.

1.2.2 Data Collection and Review

Data for the FWLB (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for FWLB (PWR) is 1988–2010. Figure 1-2 shows the trend of the full FWLB (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the FWLB (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 1-3 summarizes the data obtained from RADS and used in the FWLB (PWR) analysis.

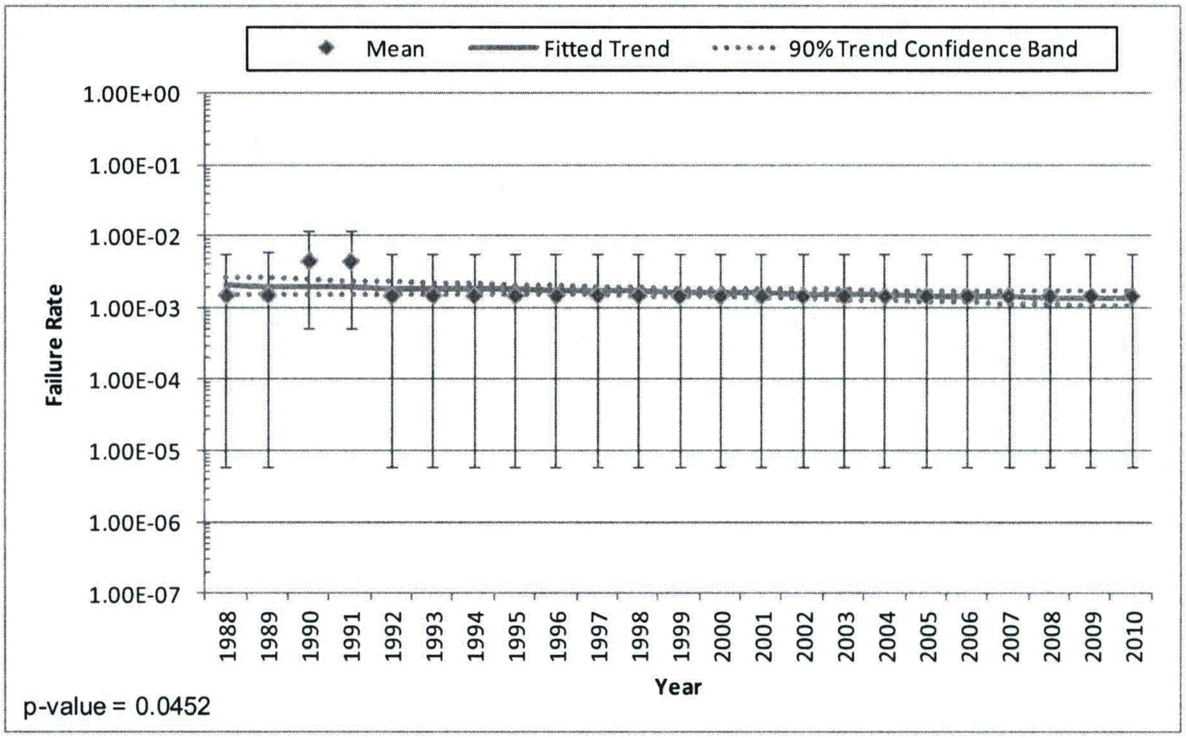

Figure 1-2. FWLB (PWR) trend plot.

Table 1-3. FWLB (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
2	1362.8	1988-2010	76	2.6%

1.2.3 Industry-Average Baselines

Table 1-4 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 1-4. Selected industry distribution of λ for FWLB (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	4.20E-04	1.60E-03	1.83E-03	4.06E-03	Gamma	2.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

1.3 Steamline Break inside Containment

1.3.1 Initiating Event Description

From Reference 3, the Steam Line Break inside Containment (PWR) (SLBIC (PWR)) initiating event is a break of one-inch equivalent diameter or more in a steam line located inside the primary containment that contains main turbine working fluid at or above atmospheric saturation conditions.

This category applies to PWRs only. Examples include: breeches of a pipe caused by a split, crack, weld failure, or circumferential break.

1.3.2 Data Collection and Review

Data for the SLBIC (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SLBIC (PWR) is 1988–2010. Figure 1-3 shows the trend of the full SLBIC (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the SLBIC (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 1-5 summarizes the data obtained from RADS and used in the SLBIC (PWR) analysis.

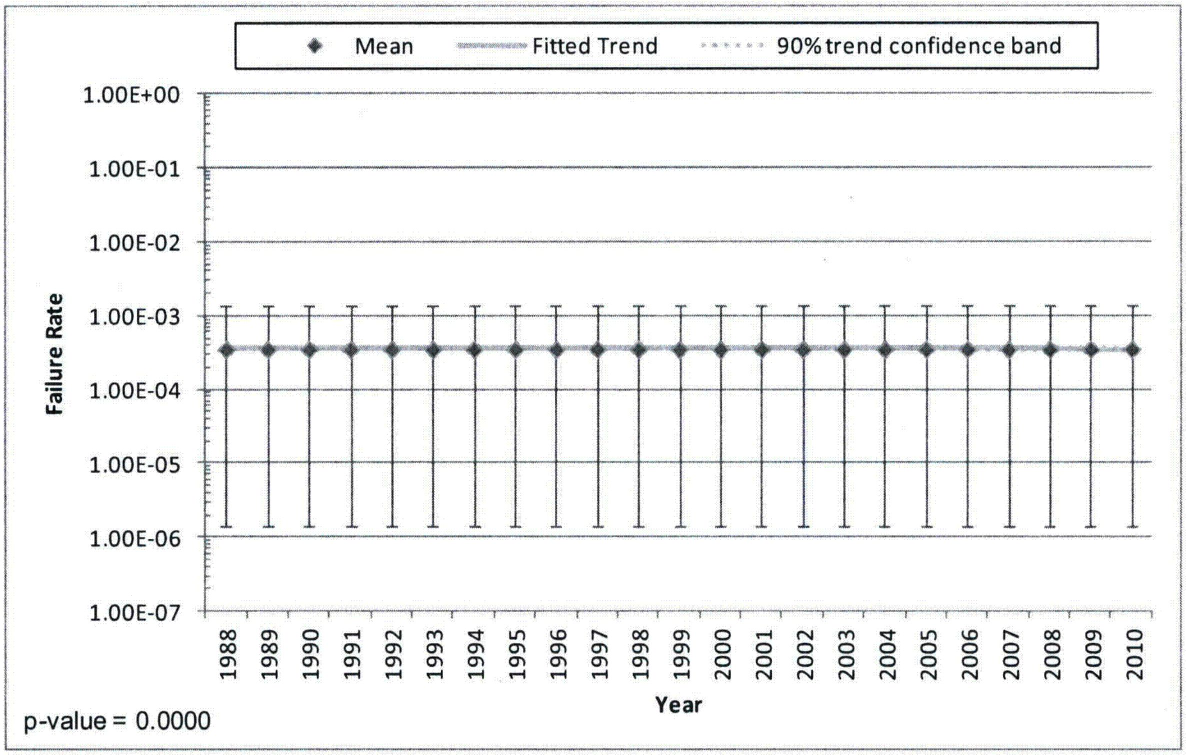

Figure 1-3. SLBIC (PWR) trend plot.

Table 1-5. SLBIC (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	1362.8	1988-2010	76	0.0%

1.3.3 Industry-Average Baselines

Table 1-6 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 1-6. Selected industry distribution of λ for SLBIC (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.44E-06	1.67E-04	3.67E-04	1.41E-03	Gamma	0.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

1.4 Steamline Break outside Containment (BWR)

1.4.1 Initiating Event Description

From Reference 3, the Steam Line Break outside Containment at Boiling Water Reactors (SLBOC (BWR)) initiating event is a break of one-inch equivalent diameter or more in a steam line located outside the primary containment that contains main turbine working fluid at or above atmospheric saturation conditions.

Examples include: operation of rupture disks; and breeches of a pipe caused by a split, crack, weld failure, or circumferential break.

1.4.2 Data Collection and Review

Data for the SLBOC (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SLBOC (BWR) is 1988–2010. Figure 1-4 shows the trend of the full SLBOC (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the SLBOC (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 1-7 summarizes the data obtained from RADS and used in the SLBOC (BWR) analysis.

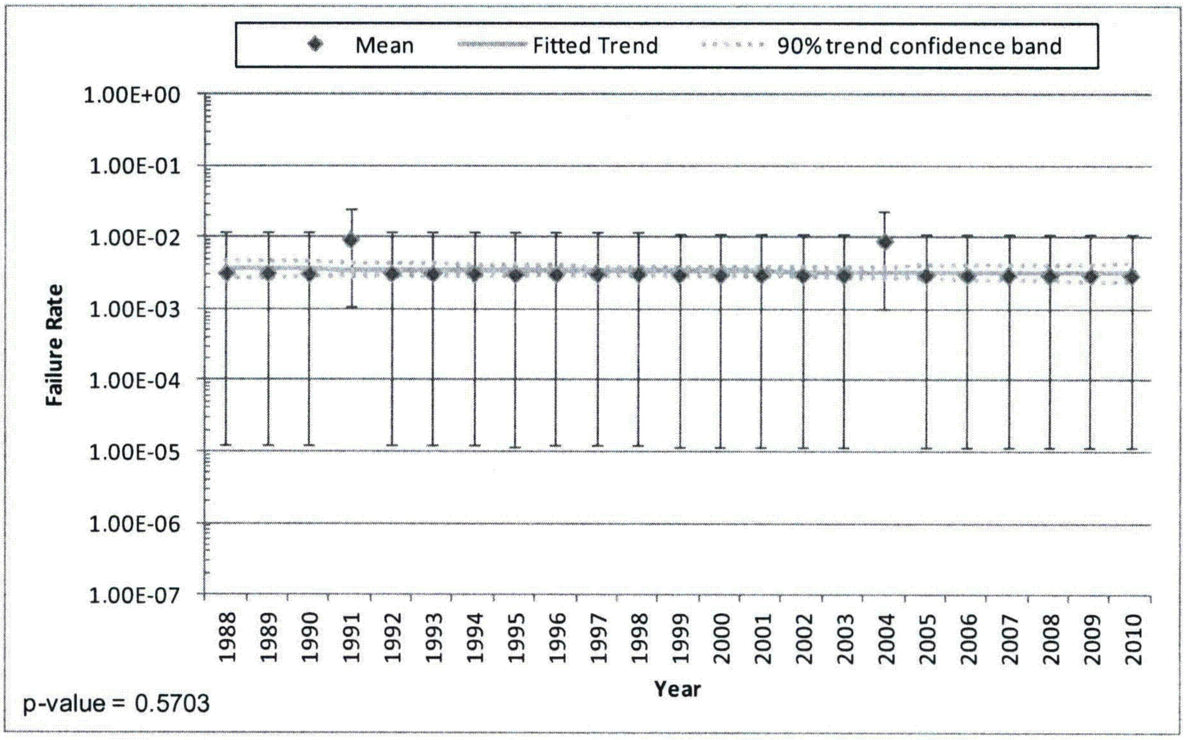

Figure 1-4. SLBOC (BWR) trend plot.

Table 1-7. SLBOC (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
2	672.9	1988-2010	38	5.3%

1.4.3 Industry-Average Baselines

Table 1-8 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 1-8. Selected industry distribution of λ for SLBOC (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	8.51E-04	3.23E-03	3.72E-03	8.23E-03	Gamma	2.500	6.729E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

1.5 Steamline Break outside Containment (PWR)

1.5.1 Initiating Event Description

From Reference 3, the Steam Line Break outside Containment at Pressurized Water Reactors (SLBOC (PWR)) initiating event is a break of one-inch equivalent diameter or more in a steam line located outside the primary containment that contains main turbine working fluid at or above atmospheric saturation conditions.

Examples include: operation of rupture disks; and breeches of a pipe caused by a split, crack, weld failure, or circumferential break.

1.5.2 Data Collection and Review

Data for the SLBOC (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SLBOC (PWR) is 1988–2010. Figure 1-5 shows the trend of the full SLBOC (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the SLBOC (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry.

Table 1-9 summarizes the data obtained from RADS and used in the SLBOC (PWR) analysis.

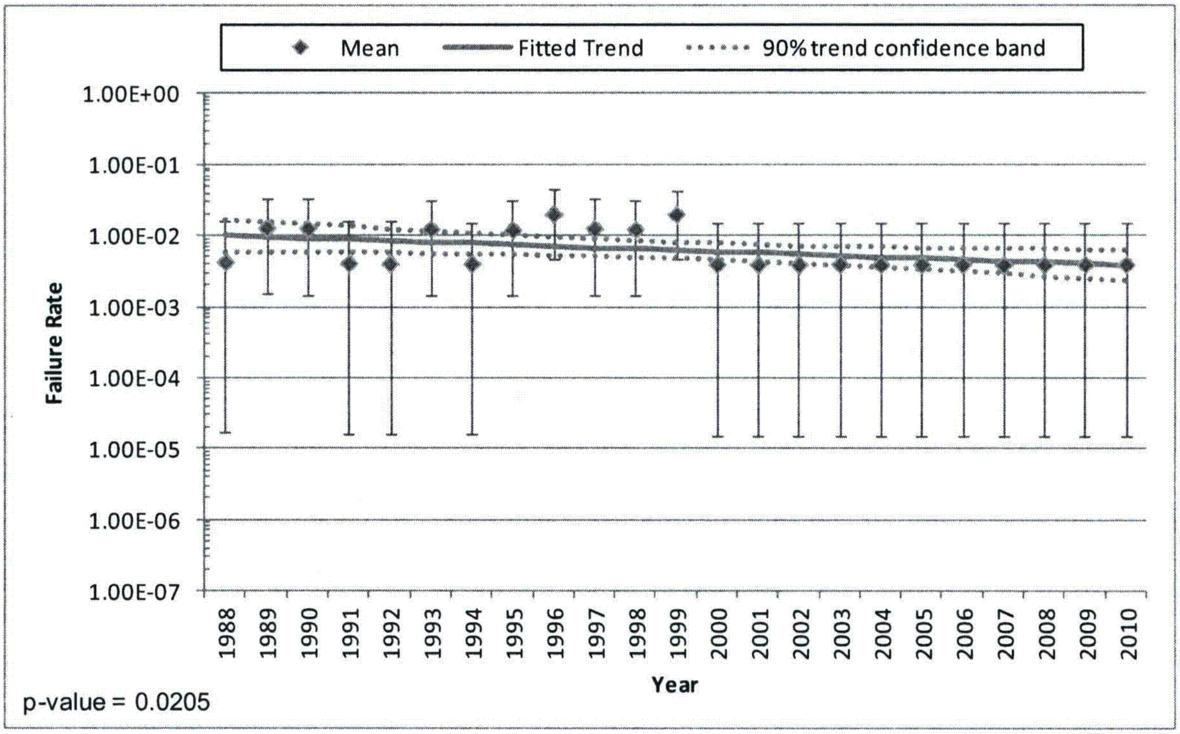

Figure 1-5. SLBOC (PWR) trend plot.

Table 1-9. SLBOC (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
10	1362.8	1988-2010	76	13.2%

1.5.3 Industry-Average Baselines

Table 1-10 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 1-10. Selected industry distribution of λ for SLBOC (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	4.25E-03	7.46E-03	7.70E-03	1.20E-02	Gamma	10.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

2 Steam Generator Tube Rupture

2.1 *Steam Generator Tube Rupture (SGTR)*

2.1.1 Initiating Event Description

From Reference 3, the Steam Generator Tube Rupture (STGR) initiating event is a rupture of one or more steam generator tubes that results in a loss of primary coolant to the secondary side of the steam generator at a rate greater than or equal to 100 gallons per minute (gpm). A SGTR can occur as the initial plant fault, such as a tube rupture caused by high cycle fatigue or loose parts, or as a consequence of another initiating event. The latter case would be classified as a functional impact. This category applies to pressurized water reactors (PWRs) only. This category includes excessive leakage caused by the failure of a previous SGTR repair (i.e., leakage past a plug).

2.1.2 Data Collection and Review

Two methodologies are summarized in this section. For one approach, information for the SGTR baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the SGTR frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

From Table 7.3 in Reference 5, the mean frequency for SGTR ((> 100 gpm) is 3.4E-3/reactor calendar year (rcy). To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(3.40E-4/rcy)(1 rcy/0.9 rcry) = 3.78E-3/rcry.

The associated error factor (95th percentile divided by median) associated with the SGTR category from Reference 5 is

(8.2E-3/rcy)/(2.6E-3/rcy) = 3.2,

which converts to an α of 1.6.

For the other approach, data for the SGTR baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SGTR is 1991–2010. Figure 2-1 shows the trend of the full SGTR data set and the baseline period used in this analysis. The RADS database was used to collect the SGTR data for that period. Results include total number of events and total rcry's for the U.S. commercial nuclear power plant industry. Table 2-1 summarizes the data obtained from RADS and used in the SGTR analysis.

Table 2-1. STGR frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
2	1205.2	1991-2010	75	2.7%

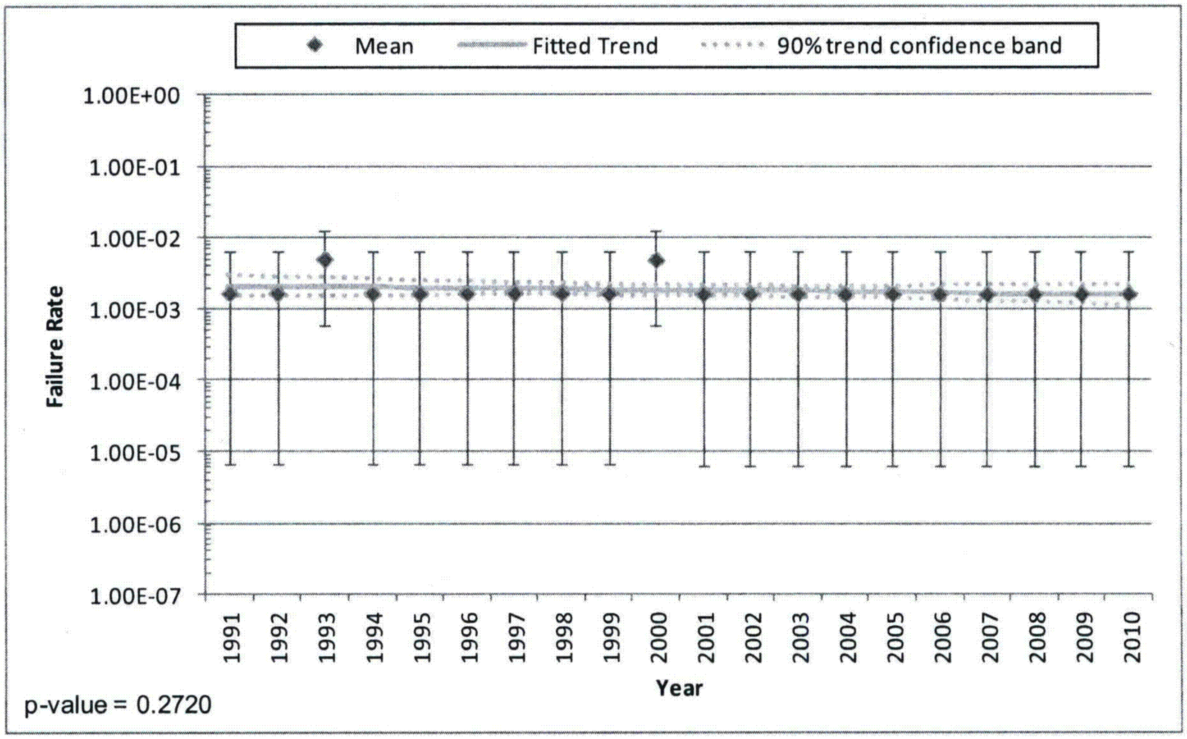

Figure 2-1. SGTR trend plot.

2.1.3 Industry-Average Baselines

Table 2-2 lists the industry-average frequency distribution. Two different approaches to estimating the frequency for SGTR were discussed – the expert elicitation approach from Reference 5, and the data analysis using the IEDB. Because the expert elicitation process outlined in Reference 5 resulted in a mean frequency for SGTR (3.78E-3/rcry) which is higher than that obtained from optimizing the SGTR data from the IEDB (2.07E-03/rcry), the IEDB results were used. This industry-average frequency does not account for any recovery.

Table 2-2. Selected industry distribution of λ for SGTR.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	4.75E-04	1.81E-03	2.07E-03	4.59E-03	Gamma	2.500	1.205E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3 Loss of Coolant Accidents

3.1 Large Loss-of-Coolant Accident at Boiling Water Reactors (LLOCA (BWR))

3.1.1 Initiating Event Description

The Large Loss-of-Coolant Accident at Boiling Water Reactors (LLOCA (BWR)) is a break size greater than 0.1 square feet (or an approximately 5-inch inside diameter pipe equivalent for liquid and steam) in a pipe in the primary system boundary.

3.1.2 Data Collection and Review

Information for the LLOCA (BWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the LLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gallon per minute (gpm) break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the LLOCA frequency (in reactor calendar years or rcy's) for BWRs is 6.1E-6/rcy (> 7 inch). To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(6.1E-6/rcy)(1 rcy/0.9 rcry) = 6.78E-6/rcry.

The associated error factor (95th percentile divided by median) from Reference 5 is

(2.0E-5/rcy)/(2.2E-6/rcy) = 9.1,

which converts to an α of 0.47.

3.1.3 Industry-Average Baselines

Table 3-1 lists the industry-average frequency distribution.

Table 3-1. Selected industry distribution of λ for LLOCA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
Ref. 5	1.90E-08	2.91E-06	6.78E-06	2.66E-05	Gamma	0.470	6.932E+04

Note – Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.2 *Large Loss-of-Coolant Accident at Pressurized Water Reactors (LLOCA (PWR))*

3.2.1 Initiating Event Description

The Large Loss-of-Coolant Accident at Pressurized Water Reactors (LLOCA (PWR)) is a pipe break in the primary system boundary with an equivalent inside diameter greater than 6 inch.

3.2.2 Data Collection and Review

Information for the LLOCA (PWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the LLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gallon per minute (gpm) break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the LLOCA frequency (in reactor calendar years or rcy's) for PWRs is 1.2E-6/rcy (> 7 inch). To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(1.2E-6/rcy)(1 rcy/0.9 rcry) = 1.33E-6/rcry.

The associated error factor (95^{th} percentile divided by median) from Reference 5 is

(3.9E-6/rcy)/(3.1E-7/rcy) = 10.5,

which converts to an α of 0.42.

3.2.3 Industry-Average Baselines

Table 3-2 lists the industry-average frequency distribution.

Table 3-2. Selected industry distribution of λ for LLOCA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
Ref. 5	1.90E-09	5.10E-07	1.33E-06	5.43E-06	Gamma	0.420	3.158E+05

Note – Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.3 Medium Loss-of-Coolant Accident at Boiling Water Reactors (MLOCA (BWR))

3.3.1 Initiating Event Description

The Medium Loss-of-Coolant Accident at Boiling Water Reactors (MLOCA (BWR)) initiating event is defined for boiling water reactors (BWRs) as a pipe break in the primary system boundary with a break size between 0.004 to 0.1 square feet (or an approximately 1- to 5-inch inside diameter pipe equivalent) for liquid and between 0.05 to 0.1 square feet (or an approximately 4- to 5-inch inside diameter pipe equivalent) for steam.

3.3.2 Data Collection and Review

Information for the MLOCA (BWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process* (Ref. 5). In that document, the MLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gallon per minute (gpm) break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the MLOCA frequency (in reactor calendar years or rcy's) for BWRs is

1.0E-4/rcy – 6.1E-6/rcy = 9.39E-5/rcy,

where 1.0E-4/rcy is for LOCAs with an effective break size greater than 1.875-inch inside diameter, and 6.1E-6/rcy is the LLOCA value. To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(9.39E-5/rcy)(1 rcy/0.9 rcry) = 1.04E-4/rcry.

The associated error factor (95th percentile divided by median) associated with the > 1.875-inch category from Reference 5 is

(3.2E-4/rcy)/(4.8E-5/rcy) = 6.7,

which converts to an α of 0.61.

3.3.3 Industry-Average Baselines

Table 3-3 lists the industry-average frequency distribution.

Table 3-3. Selected industry distribution of λ for MLOCA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
Ref. 5	1.05-06	5.54E-05	1.04E-04	3.72E-04	Gamma	0.610	5.865E+03

Note – Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.4 *Medium Loss-of-Coolant Accident at Pressurized Water Reactors (MLOCA (PWR))*

3.4.1 Initiating Event Description

The Medium Loss-of-Coolant Accident at Pressurized Water Reactors (MLOCA (PWR)) initiating event is defined for PWRs, as a pipe break in the primary system boundary with an inside diameter between 2 and 6 inches.

3.4.2 Data Collection and Review

Information for the MLOCA (PWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the MLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gallon per minute (gpm) break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the MLOCA frequency (in reactor calendar years or rcy's) for BWRs is

4.6E-4/rcy – 1.2E-6/rcy = 4.59E-4/rcy,

where 4.6E-4/rcy is for LOCAs with an effective break size greater than 1.625-inch inside diameter, and 1.2E-6/rcy is the LLOCA value. To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(4.59E-4/rcy)(1 rcy/0.9 rcry) = 5.10E-4/rcry.

The associated error factor (95^{th} percentile divided by median) associated with the > 1.625-inch category from Reference 5 is

(1.4E-3/rcy)/(1.4E-4/rcy) = 10.0,

which converts to an α of 0.44.

3.4.3 Industry-Average Baselines

Table 3-4 lists the industry-average frequency distribution.

Table 3-4. Selected industry distribution of λ for MLOCA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
Ref. 5	9.72E-07	2.05E-04	5.10E-04	2.05E-03	Gamma	0.440	8.627E+02

Note – Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.5 Small Loss-of-Coolant Accident at Boiling Water Reactors (SLOCA (BWR))

3.5.1 Initiating Event Description

From Reference 3, the Small Loss-of-Coolant Accident (SLOCA) initiating event is defined for a boiling water reactor (BWR) as a break size less than 0.004 square feet (or a 1-inch inside diameter pipe equivalent for liquid) and less than 0.05 square feet (or an approximately 4-inch inside diameter pipe equivalent for steam) in a pipe in the primary system boundary. However, the leakage must be greater than 100 gallons per minute (gpm), which is the upper limit for the very small LOCA, or VSLOCA.

3.5.2 Data Collection and Review

Two methodologies are summarized in this section. For one approach, information for the SLOCA (BWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the SLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gpm break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the SLOCA frequency (in reactor calendar years or rcy's) for BWRs is

5.5E-4/rcy – 1.0E-4/rcy = 4.5E-4/rcy,

where 5.5E-4/rcy is for LOCAs with an effective break size greater than 0.5-inch inside diameter, and 1.0E-6/rcy is the MLOCA value. To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

(4.50E-4/rcy)(1 rcy/0.9 rcry) = 5.00E-4/rcry.

The associated error factor (95th percentile divided by median) associated with the > 0.5-in. category from Reference 5 is

(1.6E-3/rcy)/(3.0E-4/rcy) = 5.3,

which converts to an α of 0.78.

For the other approach, data for the SLOCA (BWR) baseline were also obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SLOCA (BWR) is 1988–2010. (With no events, the entire period is chosen for the baseline.) The RADS database was used to collect the SLOCA data for the baseline period. Results include total number of events and total rcry's for the U.S. commercial nuclear power plant industry.

Table 3-5 summarizes the data obtained from RADS and used in the SLOCA (BWR) analysis.

Table 3-5. SLOCA (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	672.9	1988-2010	38	0.0%

3.5.3 Industry-Average Baselines

Table 3-6 lists the industry-average frequency distribution. Two different approaches to estimating the frequency for SLOCA (BWR) were discussed – the expert elicitation approach from Reference 5, and the data analysis using the IEDB. Because the IEDB contained no events and the resulting SCNID mean (7.43E-04/rcry) is higher than the expert elicitation estimate (5.00E-4/rcry), the expert elicitation distribution was chosen. (The IEDB was considered to be too limited in terms of current BWR experience to be used, given that no events had occurred.) This industry-average frequency does not account for any recovery.

Table 3-6. Selected industry distribution of λ for SLOCA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.26E-05	3.09E-04	5.00E-04	1.64E-03	Gamma	0.780	1.560E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.6 *Small Loss-of-Coolant Accident at Pressurized Water Reactors (SLOCA (PWR))*

3.6.1 Initiating Event Description

From Reference 3, the Small Loss-of-Coolant Accident (SLOCA) initiating event is defined for a pressurized water reactor (PWR) as a pipe break in the primary system boundary with an inside diameter between 0.5 and 2 inch.

3.6.2 Data Collection and Review

Two methodologies are summarized in this section. For one approach, information for the SLOCA (PWR) baseline was obtained from *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process* (Ref. 5). In that document, the SLOCA frequency was estimated based on an expert elicitation process "...to consolidate service history data and PFM [probabilistic fracture mechanics] studies with knowledge of plant design, operation, and material performance." Reference 5 is a draft document. Results obtained from that document could change when the final report is issued.

Table 7.1 in Reference 5 presents frequencies for LOCAs exceeding various sizes indicated by gallon per minute (gpm) break flow and effective pipe size break. Six different sizes are listed, ranging from 0.5-inch diameter (> 100 gpm) to 31-inch or 41-inch diameter (> 500,000 gpm). The frequencies presented for each size indicate the frequency of LOCAs of that size or greater occurring. In addition, frequencies for each size are presented for current day conditions (assuming an average of 25 years of operation) and for end-of-life conditions (40 years of operation). For this study, frequencies appropriate for current day conditions were used.

From Table 7.1 in Reference 5, the SLOCA frequency (in reactor calendar years or rcy's) for PWRs is

$$5.9E\text{-}3/rcy - 4.6E\text{-}4/rcy = 5.44E\text{-}3/rcy,$$

where 5.9E-3/rcy is for LOCAs with an effective break size greater than 0.5-inch inside diameter (including SGTRs), and 4.6E-4/rcy is the MLOCA value. Because SPAR models SGTR as a separate initiator, the SGTR frequency must be subtracted from the above result. From Reference 5, the SGTR mean frequency is 3.4E-3/rcy. Therefore, with the SGTR contribution removed, the SLOCA frequency for PWRs is

$$5.44E\text{-}3/rcy - 3.4E\text{-}3/rcy = 2.04E\text{-}3/rcy.$$

To convert this to reactor critical years (rcry's), it was assumed that reactors are critical 90% of each year. Converting to rcry's, the result is

$$(2.04E\text{-}3/rcy)(1\ rcy/0.9\ rcry) = 2.27E\text{-}3/rcry.$$

The associated error factor (95th percentile divided by median) associated with the > 0.5-in. category from Reference 5 is

$$(1.5E\text{-}2/rcy)/(3.7E\text{-}3/rcy) = 4.1,$$

which converts to an α of 1.09.

For the other approach, data for the SLOCA (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SLOCA (PWR) is 1988–2010. (With no events, the entire period is chosen for the baseline.) The RADS database was used to collect the SLOCA data for the baseline period. Results include total number of events and total rcry's for the U.S. commercial nuclear power plant industry. Table 3-7 summarizes the data obtained from RADS and used in the SLOCA (PWR) analysis.

Table 3-7. SLOCA (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	1362.8	1988-2010	76	0.0%

3.6.3 Industry-Average Baselines

Table 3-8 lists the industry-average frequency distribution. Two different approaches to estimating the frequency for SLOCA (PWR) were discussed—the expert elicitation approach from Reference 5, and the data analysis using the IEDB. Because the expert elicitation process outlined in Reference 5 resulted in a mean frequency for SLOCA (PWR) (2.27E-3/rcry) which is higher than that obtained from optimizing the SGTR data from the IEDB (3.67E-04/rcry), the IEDB results were used. This industry-average frequency does not account for any recovery.

Table 3-8. Selected industry distribution of λ for SLOCA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.44E-06	1.67E-04	3.67E-04	1.41E-03	Gamma	0.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.7 *Very Small Loss-of-Coolant Accident at Boiling Water Reactors (VSLOCA (BWR))*

3.7.1 Initiating Event Description

From Reference 3, the Very Small Loss of Coolant Accident (VSLOCA) initiating event is a pipe break or component failure that results in a loss of primary coolant between 10 to 100 gallons per minute (gpm), but does not require the automatic or manual actuation of high-pressure injection systems. Examples include reactor coolant pump (for pressurized water reactors) or recirculating pump (for boiling water reactors) seal failures, valve packing failures, steam generator tube leaks, and instrument line fitting failures.

3.7.2 Data Collection and Review

Data for the VSLOCA (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for VSLOCA (BWR) is 1992–2010. Figure 3-1 shows the trend of the full VSLOCA (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the VSLOCA (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry.

Table 3-9 summarizes the data obtained from RADS and used in the VSLOCA (BWR) analysis.

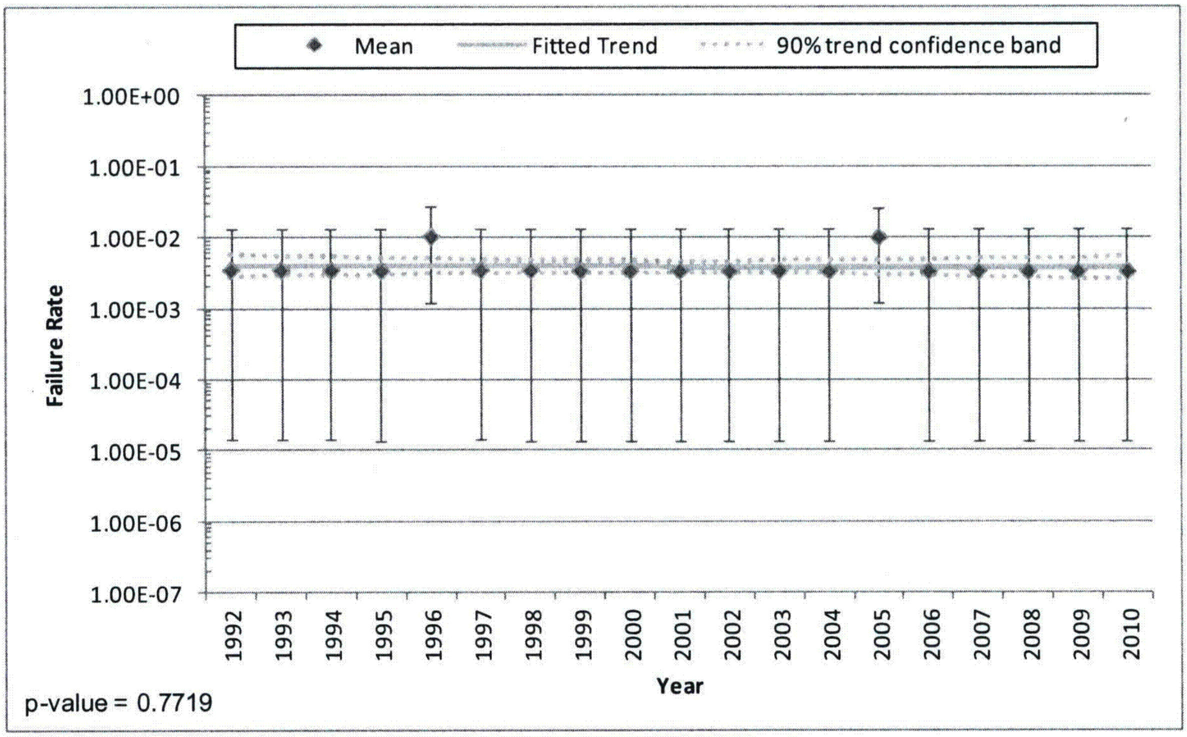

Figure 3-1. VSLOCA (BWR) trend plot.

Table 3-9. VSLOCA (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
2	574.0	1992-2010	37	5.4%

3.7.3 Industry-Average Baselines

Table 3-10 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-10. Selected industry distribution of λ for VSLOCA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	9.98E-04	3.79E-03	4.36E-03	9.64E-03	Gamma	2.500	5.740E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.8 *Very Small Loss-of-Coolant Accident at Pressurized Water Reactors (VSLOCA (PWR))*

3.8.1 Initiating Event Description

From Reference 3, the Very Small Loss of Coolant Accident (VSLOCA) initiating event is a pipe break or component failure that results in a loss of primary coolant between 10 to 100 gallons per minute (gpm), but does not require the automatic or manual actuation of high-pressure injection systems. Examples include reactor coolant pump (for pressurized water reactors) or recirculating pump (for boiling water reactors) seal failures, valve packing failures, steam generator tube leaks, and instrument line fitting failures.

3.8.2 Data Collection and Review

Data for the VSLOCA baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for VSLOCA (PWR) is 1992–2010. Figure 3-2 shows the trend of the full VSLOCA (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the VSLOCA (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry.

Table 3-11 summarizes the data obtained from RADS and used in the VSLOCA (PWR) analysis.

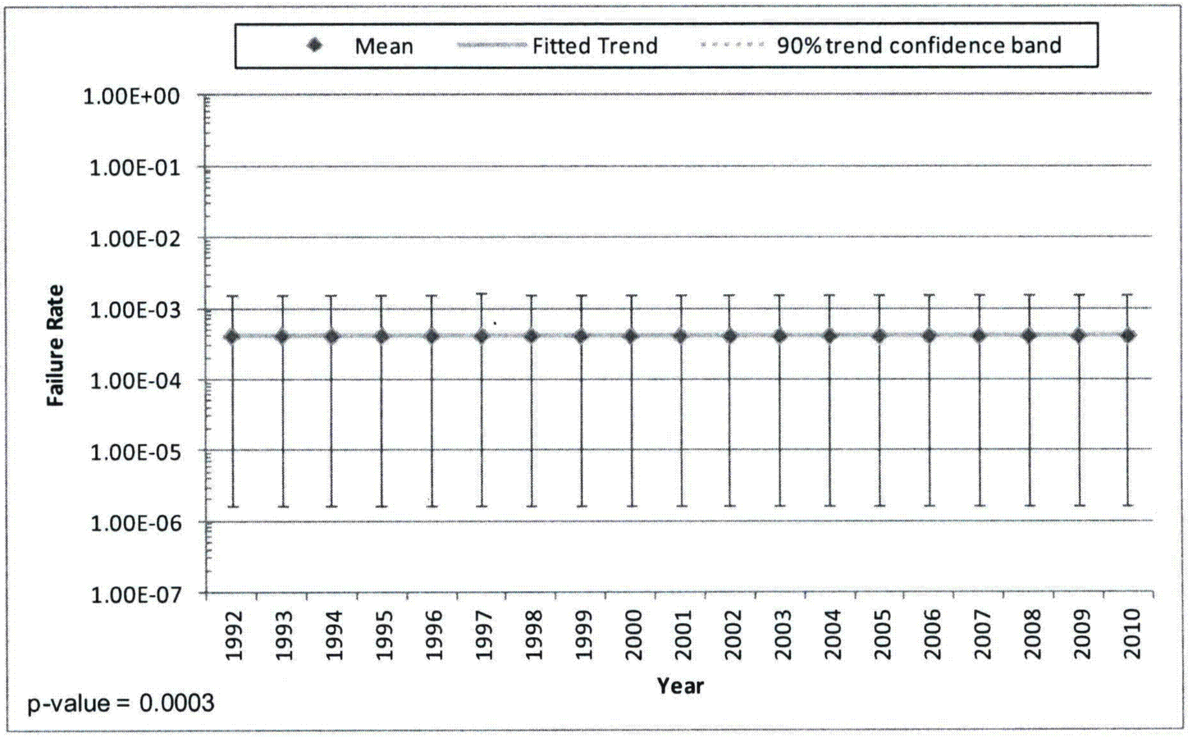

Figure 3-2. VSLOCA (PWR) trend plot.

Table 3-11. VSLOCA (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	1148.3	1992-2010	75	0.0%

3.8.3 Industry-Average Baselines

Table 3-12 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-12. Selected industry distribution of λ for VSLOCA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.71E-06	1.98E-04	4.35E-04	1.67E-03	Gamma	0.500	1.148E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.9 *Stuck Open Relief Valve at Boiling Water Reactors (SORV (BWR))*

3.9.1 Initiating Event Description

From Reference 3, the Stuck Open Relief Valve at Boiling Water Reactors (SORV (BWR)) initiating event is a failure of one primary system safety and/or relief valve (SRV) to fully close, resulting in the loss of primary coolant. The valves included in this category are main steam line safety valves (BWR) and automatic depressurization system relief valves (BWR). The stuck open SRV may or may not cause the automatic or manual actuation of high-pressure injection systems.

This category includes a stuck open valve that cannot be subsequently closed upon manual demand or does not subsequently close on its own immediately after the reactor trip. The mechanism that opens the valve is not a defining factor. The different mechanisms than can open an SRV are transient-induced opening, manual opening during valve testing, and spurious opening.

3.9.2 Data Collection and Review

Data for the SORV (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SORV (BWR) is 1993–2010. Figure 3-3 shows the trend of a single SORV (BWR) data set and the baseline period used in this analysis. There were no events for 2 or more SORV (BWR) failures.

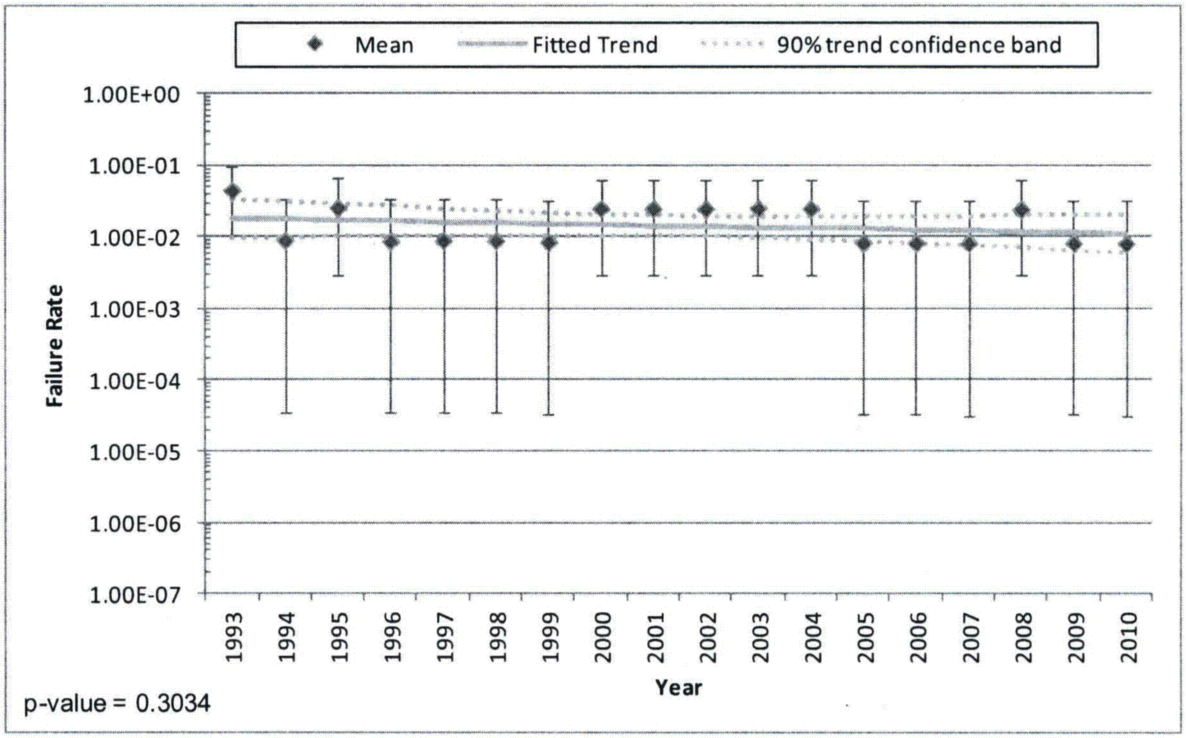

Figure 3-3. SORV (BWR) trend plot.

The RADS database was used to collect the SORV (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. The SPAR models use two SORV initiating events in the models; a single SORV (SORV1) and two or more SORVs (SORV2). The single SORV has empirical Bayes results at the plant level. Table 3-13 summarizes the data obtained from RADS and used in the SORV (BWR) analysis.

Table 3-13. SORV (BWR) frequency data for baseline period.

Event Type	Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
	Events	Reactor Critical Years (rcry)			
SORV1	9	548.8	1993-2010	37	18.9%
SORV2	0	548.8	1993-2010	37	0.0%

3.9.3 Industry-Average Baselines

Table 3-14 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-14. Selected industry distribution of λ for SORV (BWR).

Event Type	Source	5%	Median	Mean	95%	Distribution		
						Type	α	β
SORV1	EB/PL/KS	6.58E-04	1.09E-02	1.63E-02	5.06E-02	Gamma	0.912	5.580E+01
SORV2	JNID/IL	3.58E-06	4.14E-04	9.11E-04	3.50E-03	Gamma	0.500	5.488E+02

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.10 Stuck Open Relief Valve at Pressurized Water Reactors (SORV (PWR))

3.10.1 Initiating Event Description

From Reference 3, the Stuck Open Relief Valve at Pressurized Water Reactors (SORV (PWR)) initiating event is a failure of one primary system safety and/or relief valve (SRV) to fully close, resulting in the loss of primary coolant. The valves included in this category are pressurizer code safety valves (PWR). The stuck open SRV may or may not cause the automatic or manual actuation of high-pressure injection systems.

3.10.2 Data Collection and Review

Data for the SORV (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for SORV (PWR) is 1988–2010. Figure 3-4 shows the trend for a single SORV (PWR) data set and the baseline period used in this analysis. There were no events of 2 or more SORV (PWR) failures.

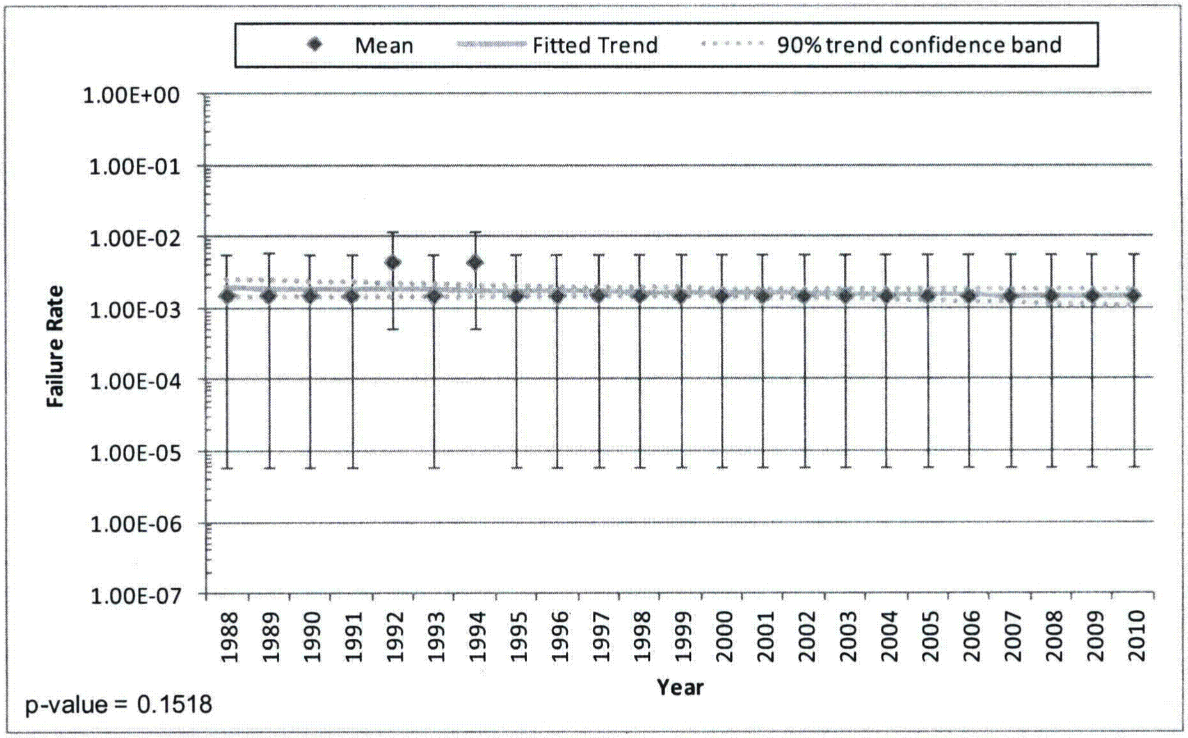

Figure 3-4. SORV (PWR) trend plot.

The RADS database was used to collect the SORV (PWR) data for that period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Results are shown for two SORV initiating events; a single SORV (SORV1) and two or more SORVs (SORV2). Table 3-15 summarizes the data obtained from RADS and used in the SORV (PWR) analysis.

Table 3-15. SORV (PWR) frequency data for baseline period.

Event Type	Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
	Events	Reactor Critical Years (rcry)			
SORV1	2	1362.8	1988-2010	76	2.6%
SORV2	0	1362.8	1988-2010	76	0.0%

3.10.3 Industry-Average Baselines

Table 3-16 lists the industry-average frequency distribution. With only two events, an empirical Bayes analysis could not be performed. Therefore, the SCNID analysis results were used. This industry-average frequency does not account for any recovery.

Table 3-16. Selected industry distribution of λ for SORV (PWR).

Event Type	Source	5%	Median	Mean	95%	Distribution Type	α	β
SORV1	JNID/IL	4.20E-04	1.60E-03	1.83E-03	4.06E-03	Gamma	2.500	1.363E+03
SORV2	JNID/IL	1.44E-06	1.67E-04	3.67E-04	1.41E-03	Gamma	0.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.11 *Interfacing System Loss-of-Coolant Accident at Boiling Water Reactors*

3.11.1 Initiating Event Description

From Reference 3, the Interfacing System LOCA (ISLOCA) initiating event is a backflow of high-pressure coolant from the primary system through low-pressure system piping which results in the breach of the pipe or component.

3.11.2 Data Collection and Review

Data for the ISLOCA baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for ISLOCA (BWR) is 1988–2010. Figure 3-5 shows the trend of the full ISLOCA (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the ISLOCA (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 3-17 summarizes the data obtained from RADS and used in the ISLOCA (BWR) analysis.

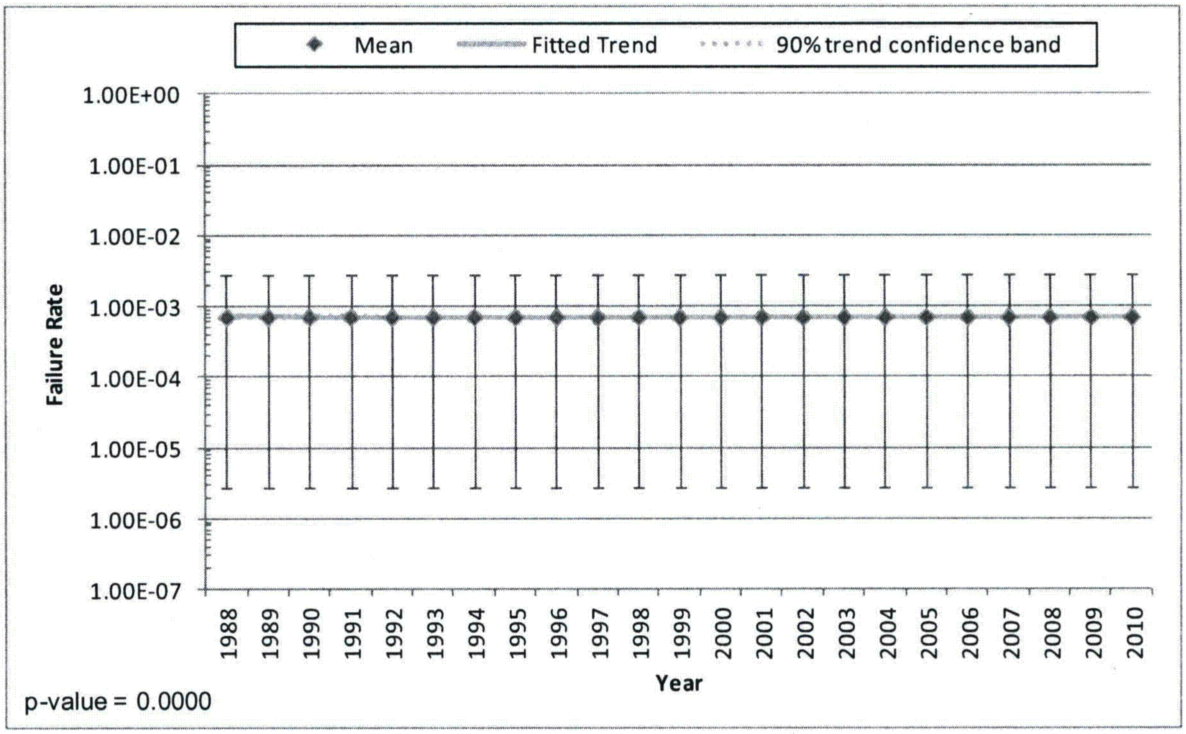

Figure 3-5. ISLOCA (BWR) trend plot.

Table 3-17. ISLOCA (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	672.9	1988-2010	38	0.0%

3.11.3 Industry-Average Baselines

Table 3-18 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-18. Selected industry distribution of λ for ISLOCA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	2.92E-06	3.38E-04	7.43E-04	2.85E-03	Gamma	0.500	6.729E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.12 Interfacing System Loss-of-Coolant Accident at Presssurized Water Reactors

3.12.1 Initiating Event Description

From Reference 3, the Interfacing System LOCA (ISLOCA) initiating event is a backflow of high-pressure coolant from the primary system through low-pressure system piping which results in the breach of the pipe or component.

3.12.2 Data Collection and Review

Data for the ISLOCA baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for ISLOCA (PWR) is 1988–2010. Figure 3-6 shows the trend of the full ISLOCA (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the ISLOCA (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 3-19 summarizes the data obtained from RADS and used in the ISLOCA (PWR) analysis.

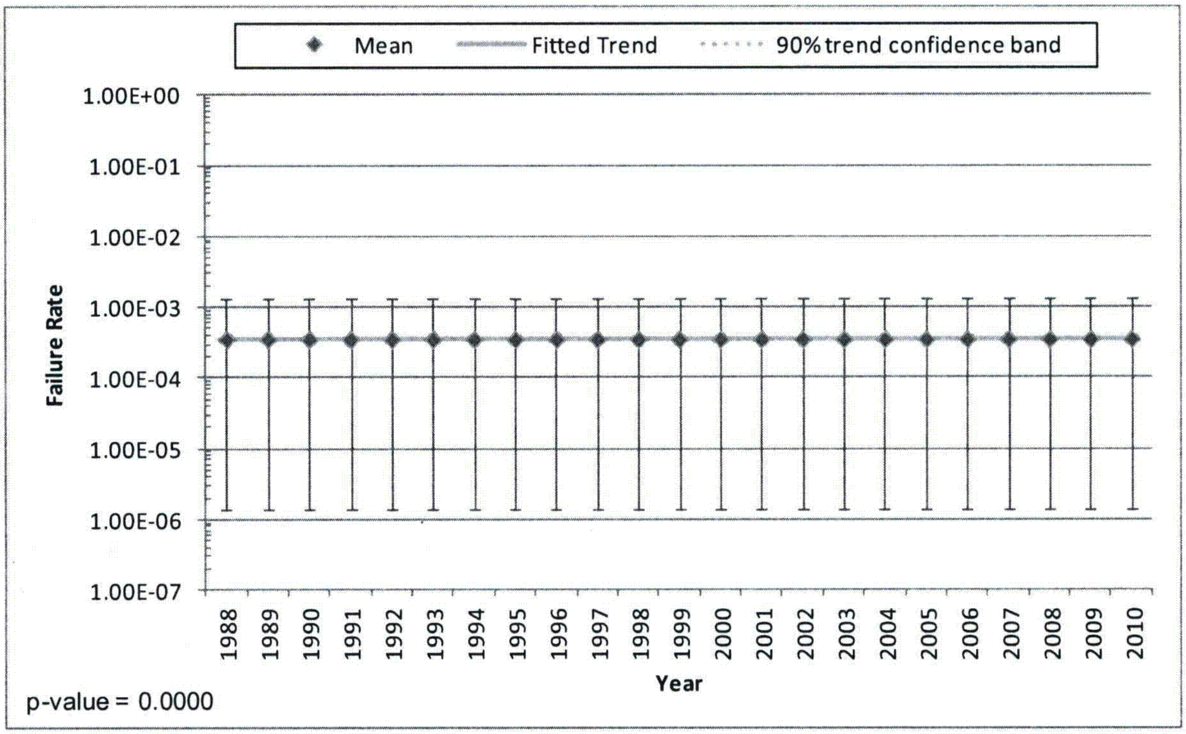

Figure 3-6. ISLOCA (PWR) trend plot.

Table 3-19. ISLOCA (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	1362.8	1988-2010	76	0.0%

3.12.3 Industry-Average Baselines

Table 3-20 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-20. Selected industry distribution of λ for ISLOCA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.44E-06	1.67E-04	3.67E-04	1.41E-03	Gamma	0.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

3.13 Reactor Coolant Pump Seal LOCA (RCPLOCA)

3.13.1 Initiating Event Description

From Reference 3, the Reactor Coolant Pump Seal LOCA (RCPLOCA) initiating event is a catastrophic failure the reactor coolant pump seal assembly that results in a primary coolant leak into the primary containment at a rate greater than 100 gpm. This category applies to PWRs only.

3.13.2 Data Collection and Review

Data for the RCPLOCA baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for RCPLOCA is 1988–2010. Figure 3-6 shows the trend of the full RCPLOCA data set and the baseline period used in this analysis. The RADS database was used to collect the RCPLOCA data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 3-19 summarizes the data obtained from RADS and used in the RCPLOCA analysis.

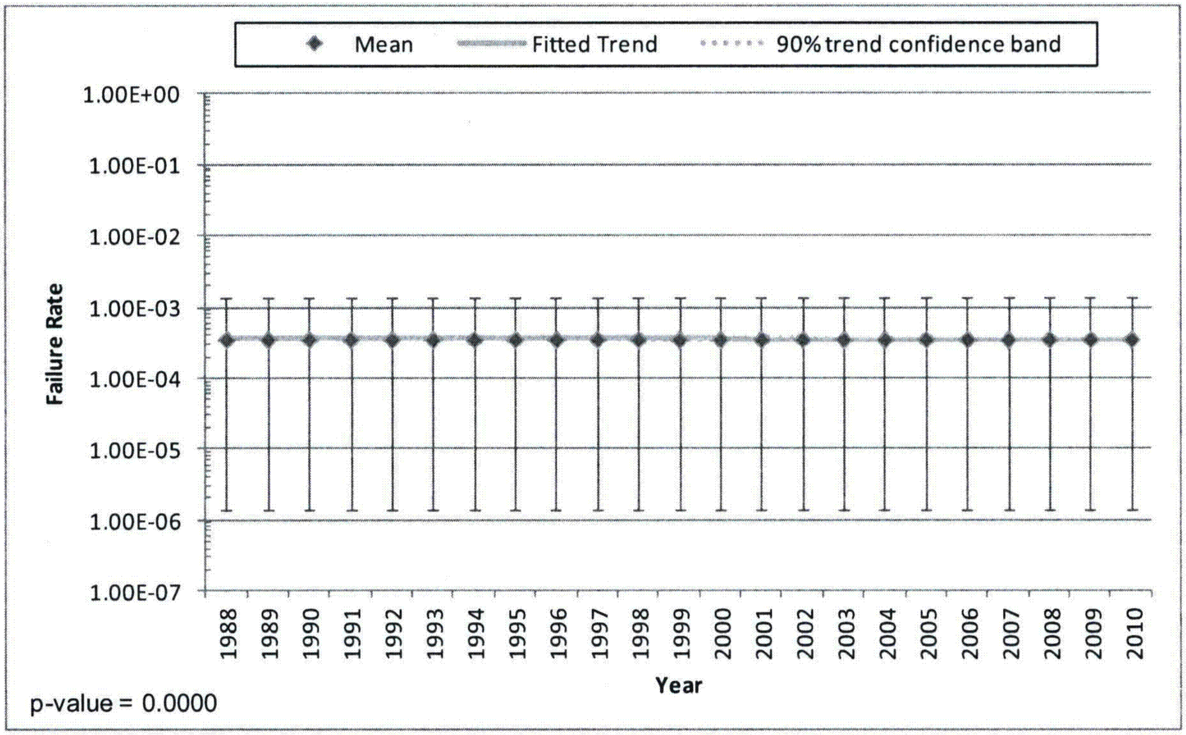

Figure 3-7. RCPLOCA trend plot.

Table 3-21. RCPLOCA frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	1362.8	1988-2010	76	0.0%

3.13.3 Industry-Average Baselines

Table 3-20 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 3-22. Selected industry distribution of λ for RCPLOCA.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	1.44E-06	1.67E-04	3.67E-04	1.41E-03	Gamma	0.500	1.363E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

4 Loss of Power

4.1 Loss of Offsite Power (LOOP)

4.1.1 Initiating Event Description

From Reference 3, the Loss of Offsite Power (LOOP) initiating event is a simultaneous loss of electrical power to all safety-related buses that causes emergency power generators to start and supply power to the safety-related buses. The offsite power boundary extends from the offsite electrical power grid to the output breaker (inclusive) of the step-down transformer that feeds the first safety-related bus with an emergency power generator. The plant switchyard and service-type transformers are included within the offsite power boundary. This category includes the momentary or prolonged degradation of grid voltage that causes all emergency power generators to start (if operable) and load onto their associated safety-related buses (if available).

This category does not include a LOOP event that occurs while the plant is shutdown. In addition, it does not include any momentary undervoltage event that results in the automatic start of all emergency power generators, but in which the generators do not tie on to their respective buses due to the short duration of the undervoltage.

4.1.2 Data Collection and Review

The LOOP data were obtained directly from the 2010 update to the report *Reevaluation of Station Blackout Risk at Nuclear Power Plants* (Ref. 4). A baseline period of 1997–2010 was used in that report. Table 4-1 summarizes the data used in the LOOP analysis. Figure 4-1 shows the trend of the full LOOP data set and the baseline period used in this analysis.

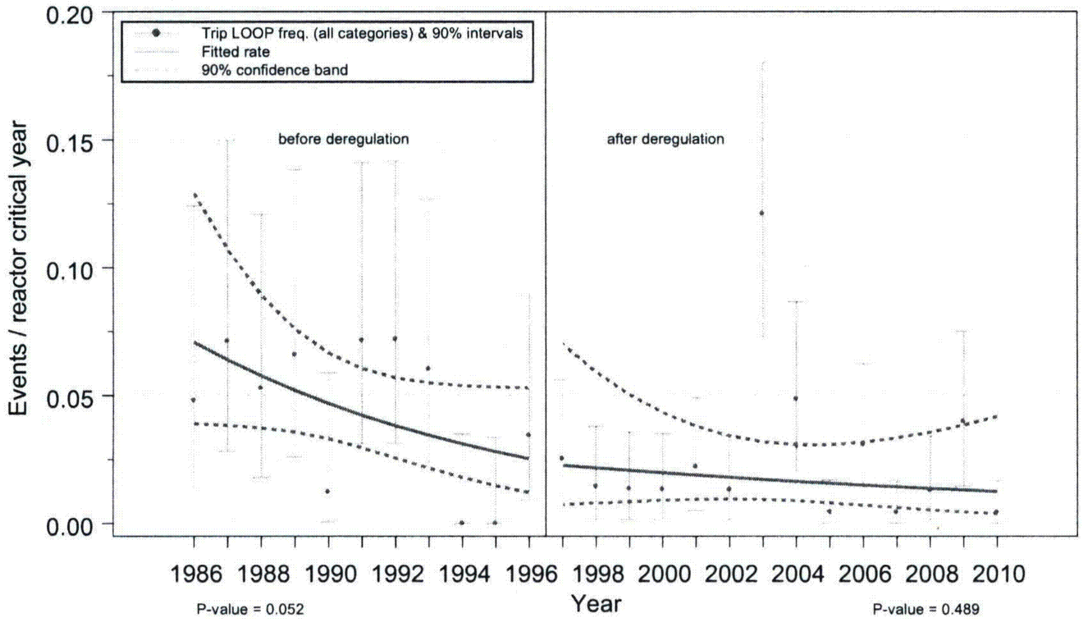

Figure 4-1. LOOP trend plot.

Table 4-1. LOOP frequency data for baseline period.

LOOP Category	Data After Review		Baseline Period	Counts Number of Plants	Percent of Plants with Events
	Events	Reactor Critical Years (rcry)			
Plant Centered	2	1294.0	1997–2010	104	1.0%
Switchyard Centered	13	1294.0	1997–2010	104	6.8%
Grid Related	14	1294.0	1997–2010	104	12.6%
Weather Related	8	2171.4	1986–2010	104	2.9%
Total LOOP	37	1417.9		104	22.3%

4.1.3 Industry-Average Baselines

Table 4-2 lists the industry-average frequency distributions for the four LOOP categories and total LOOP. These industry-average frequencies do not account for any recovery.

Table 4-2. Selected industry distributions of λ for LOOP.

Event	Source	5%	Median	Mean	95%	Distribution		
						Type	α	β
Plant Centered	LOOP	4.43E-04	1.68E-03	1.93E-03	4.28E-03	Gamma	2.5	1294.0
Switchyard Centered	LOOP	6.24E-03	1.02E-02	1.04E-02	1.55E-02	Gamma	13.5	1294.0
Grid Related	LOOP	1.17E-05	4.37E-03	1.22E-02	5.09E-02	Gamma	0.40	32.4
Weather Related	LOOP	2.00E-03	3.76E-03	3.91E-03	6.35E-03	Gamma	8.5	2171.4
Total LOOP	LOOP	1.28E-02	2.11E-02	2.71E-02	6.23E-02	Gamma	2.82	104.1

Note – Percentiles and the mean have units of events/rcry. The units for β are rcry.

5 Loss of Condenser Heat Sink

5.1 Loss of Condenser Heat Sink at Boiling Water Reactors (LOCHS (BWR))

5.1.1 Initiating Event Description

From Reference 3, the Loss of Condenser Heat Sink at Boiling Water Reactors (LOCHS (BWR)) initiating event is defined as at least one of the following:

1. A complete closure of at least one main steam isolation valve in each main steam line.
2. A decrease in condenser vacuum that leads to an automatic or manual reactor trip, or manual turbine trip; or a complete loss of condenser vacuum that prevents the condenser from removing decay heat after a reactor trip. In addition, reactor trips that are the indirect result of a low condenser vacuum, such as a loss of feedwater caused by condensate pumps tripping on high condensate temperature because of loss of vacuum, are counted.
3. The failure of one or more turbine bypass valves to maintain the reactor pressure and temperature at the desired operating condition.

5.1.2 Data Collection and Review

Data for the LOCHS (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOCHS (BWR) is 1996–2010. Figure 5-1 shows the trend of the full LOCHS (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the LOCHS (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 5-1 summarizes the data obtained from RADS and used in the LOCHS (BWR) analysis.

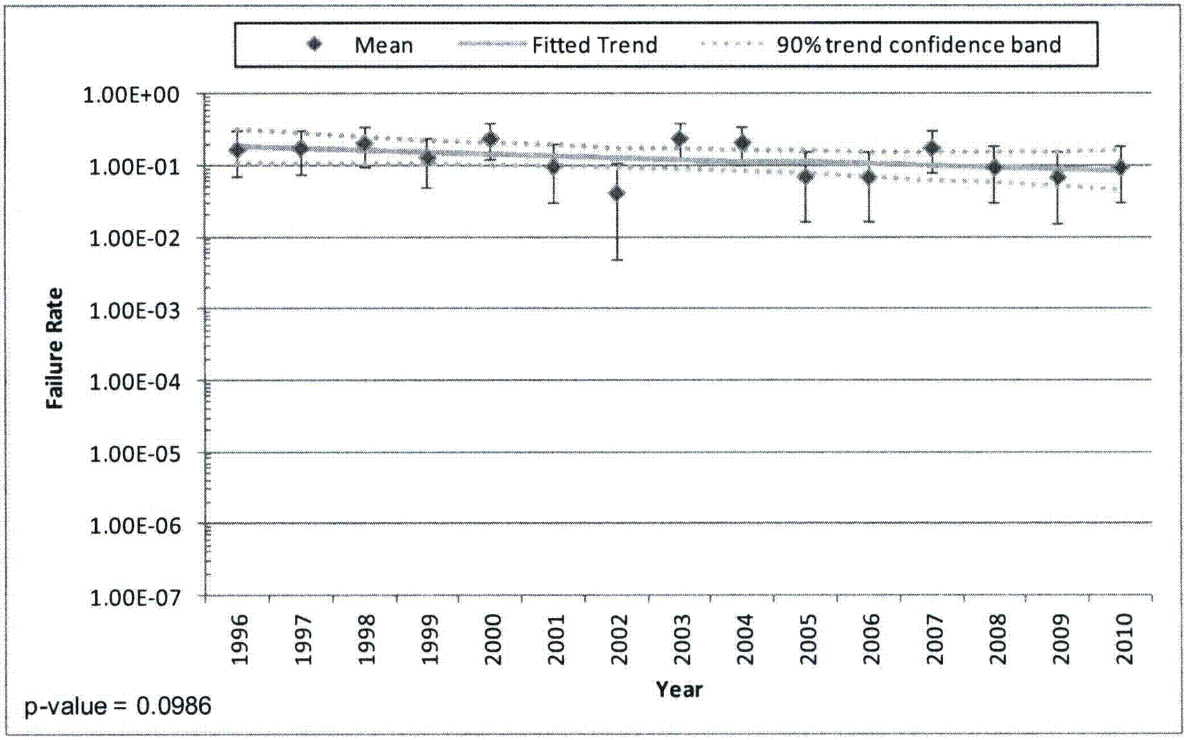

Figure 5-1. LOCHS (BWR) trend plot.

Table 5-1. LOCHS (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
65	465.6	1996-2010	36	75.0%

5.1.3 Industry-Average Baselines

Table 5-2 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 5-2. Selected industry distribution of λ for LOCHS (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	3.69E-02	1.24E-01	1.39E-01	2.95E-01	Gamma	2.903	2.085E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

5.2 Loss of Condenser Heat Sink at Pressurized Water Reactors (LOCHS (PWR))

5.2.1 Initiating Event Description

From Reference 3, the Loss of Condenser Heat Sink at Pressurized Water Reactors (LOCHS (PWR)) initiating event is defined as at least one of the following:

1. A complete closure of at least one main steam isolation valve in each main steam line.
2. A decrease in condenser vacuum that leads to an automatic or manual reactor trip, or manual turbine trip; or a complete loss of condenser vacuum that prevents the condenser from removing decay heat after a reactor trip. In addition, reactor trips that are the indirect result of a low condenser vacuum, such as a loss of feedwater caused by condensate pumps tripping on high condensate temperature because of loss of vacuum, are counted.
3. The failure of one or more turbine bypass valves to maintain the reactor pressure and temperature at the desired operating condition.

5.2.2 Data Collection and Review

Data for the LOCHS (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOCHS (PWR) is 1995–2010. Figure 5-2 shows the trend of the full LOCHS (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the LOCHS (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 5-3 summarizes the data obtained from RADS and used in the LOCHS (PWR) analysis.

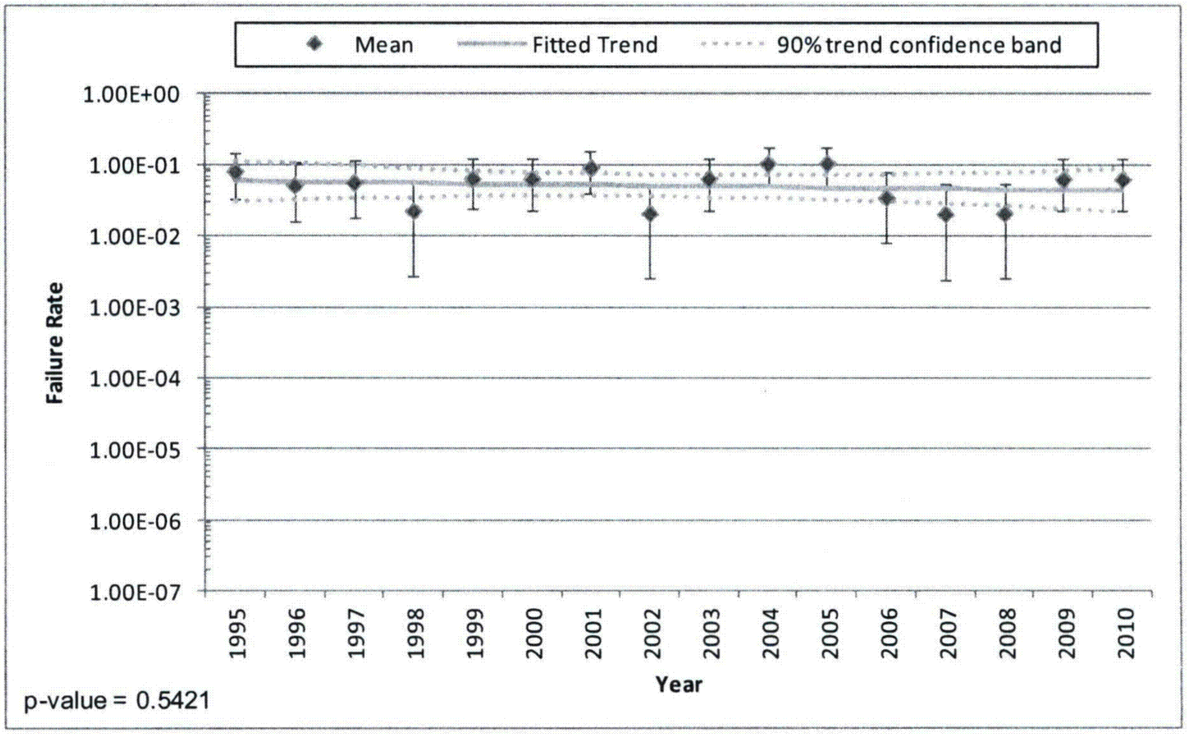

Figure 5-2. LOCHS (PWR) trend plot.

Table 5-3. LOCHS (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
57	974.7	1995-2010	73	47.9%

5.2.3 Industry-Average Baselines

Table 5-4 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 5-4. Selected industry distribution of λ for LOCHS (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	1.91E-02	5.35E-02	5.86E-02	1.16E-01	Gamma	3.741	6.383E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

6 Loss of Feedwater

6.1 *Loss of Main Feedwater (LOMFW)*

6.1.1 Initiating Event Description

From Reference 3, the Loss of Main Feedwater (LOMFW) initiating event is a complete loss of all main feedwater flow. Examples include the following: trip of the only operating feedwater pump while operating at reduced power; the loss of a startup or an auxiliary feedwater pump normally used during plant startup; the loss of all operating feed pumps due to trips caused by low suction pressure, loss of seal water, or high water level (boiling water reactor vessel level or pressurized water reactor steam generator level); anticipatory reactor trip due to loss of all operating feed pumps; and manual reactor trip in response to feed problems characteristic of a total loss of feedwater flow, but prior to automatic reactor protection system signals. This category also includes the inadvertent isolation or closure of all feedwater control valves prior to the reactor trip; however, a main feedwater isolation caused by valid automatic system response after a reactor trip is not included. This category does not include the total loss of feedwater caused by the loss of offsite power.

6.1.2 Data Collection and Review

Data for the LOMFW baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOMFW is 1993–2010. Figure 6-1 shows the trend of the full LOMFW data set and the baseline period used in this analysis. The RADS database was used to collect the LOMFW data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. Table 6-1 summarizes the data obtained from RADS and used in the LOMFW analysis.

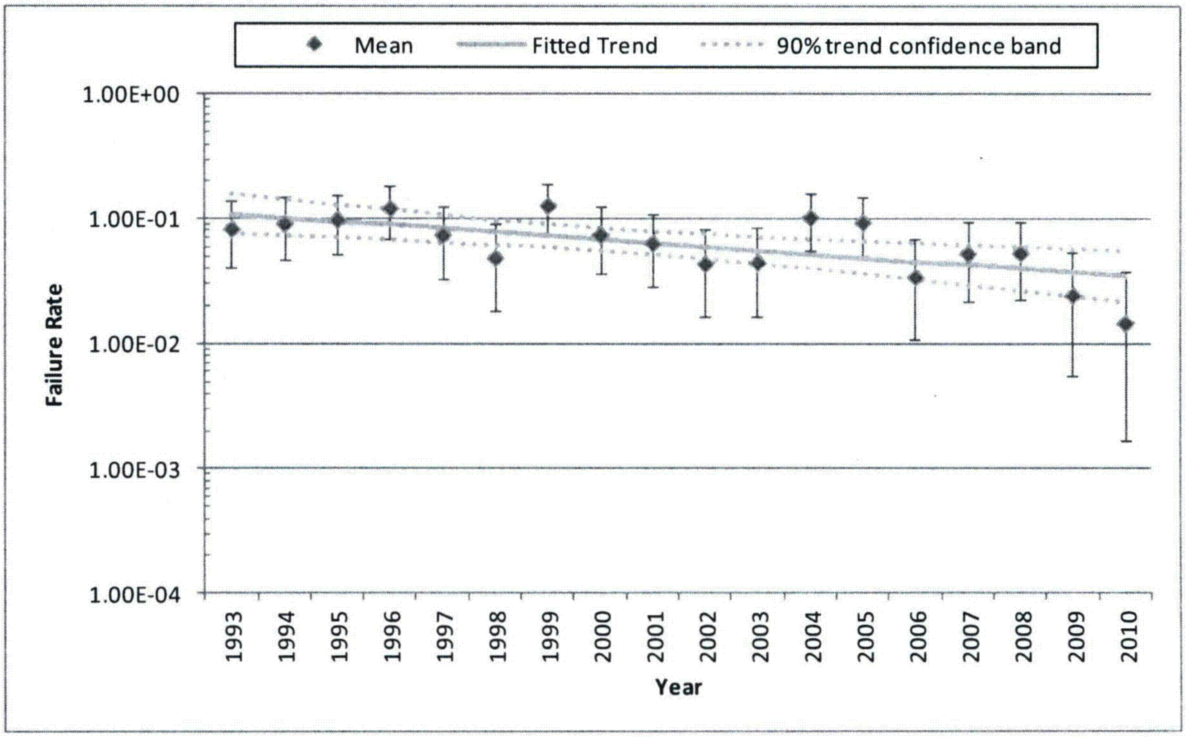

Figure 6-1. LOMFW trend plot.

Table 6-1. LOMFW frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
113	1638.8	1993-2010	110	52.7%

6.1.3 Industry-Average Baselines

Table 6-2 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 6-2. Selected industry distribution of λ for LOMFW.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	1.39E-02	5.89E-02	6.89E-02	1.58E-01	Gamma	2.220	3.221E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7 Loss of Support Systems

7.1 Loss of Safety-Related Bus

7.1.1 Loss of Vital AC Bus (LOAC)

7.1.1.1 Initiating Event Description

From Reference 3, the Loss of Vital AC Bus (LOAC) initiating event is any sustained de-energization of a safety-related bus due to the inability to connect to any of the normal or alternative electrical power supplies. The bus must be damaged or its power source unavailable for reasons beyond an open, remotely-operated feeder-breaker from a live power source. Examples include supply cable grounds, failed insulators, damaged disconnects, transformer deluge actuations, and improper uses of grounding devices.

7.1.1.2 Data Collection and Review

Data for the LOAC baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOAC is 1992–2010. Figure 7-1 shows the trend of the full LOAC data set and the baseline period used in this analysis. The RADS database was used to collect the LOAC data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-1 summarizes the baseline data obtained from RADS and used in the LOAC analysis.

The LOAC results shown here in Table 7-1 and Table 7-2 include a calculated value to adjust the LOAC frequency to use in PRA models where the LOAC initiator can be caused by more than a single AC bus. The calculated value (LOAC2) consists of dividing the mean by two and recalculating the uncertainty using an alpha parameter of 0.3.

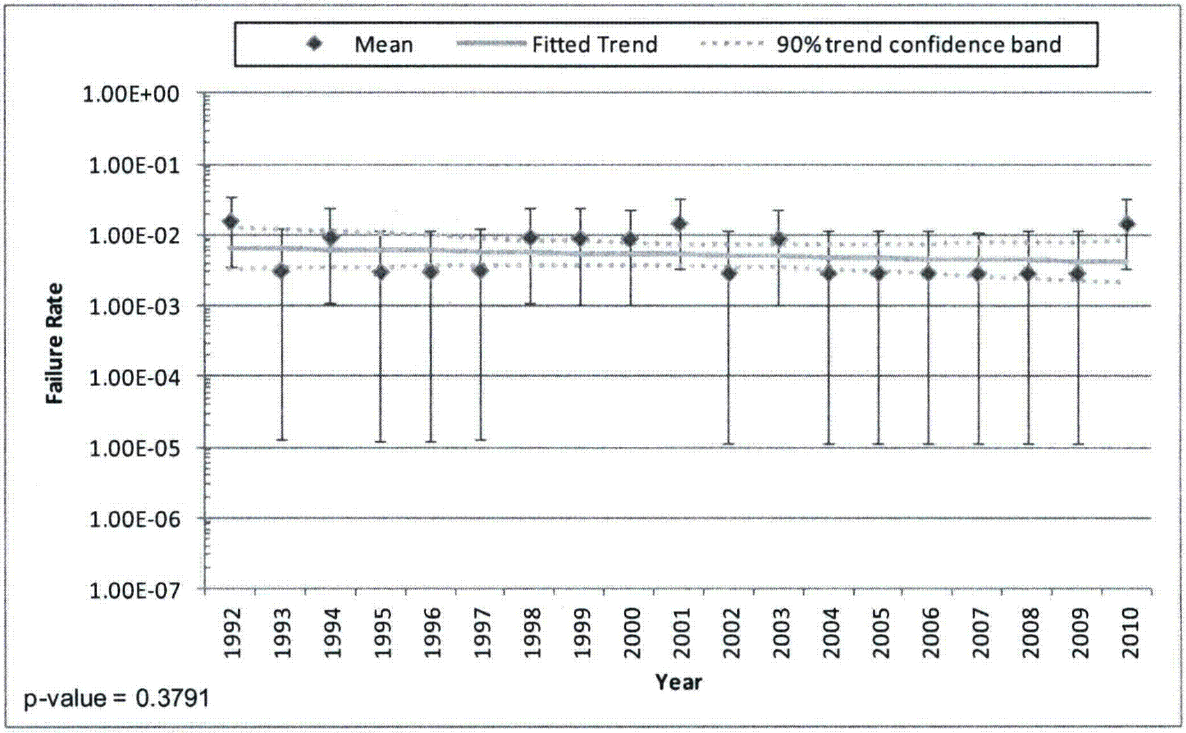

Figure 7-1. LOAC trend plot.

Table 7-1. LOAC frequency data for baseline period.

IE	Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
	Events	Reactor Critical Years (rcry)			
LOAC	11	1722.4	1992-2010	112	9.8%
LOAC 4160V FI	7	1722.4	1992-2010	112	6.3%
LOAC LOWV FI	4	1722.4	1992-2010	112	3.6%
LOAC 2	11	1722.4	1992-2010	112	9.8%

7.1.1.3 Industry-Average Baselines

Table 7-2 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-2. Selected industry distribution of λ for LOAC.

IE	Source	5%	Median	Mean	95%	Distribution		
						Type	α	β
LOAC	JNID/IL	3.80E-03	6.48E-03	6.68E-03	1.02E-02	Gamma	11.500	1.722E+03
LOAC 4160V	JNID/IL	2.11E-03	4.16E-03	4.35E-03	7.26E-03	Gamma	7.500	1.722E+03
LOAC LOWV	JNID/IL	9.65E-04	2.42E-03	2.61E-03	4.91E-03	Gamma	4.500	1.722E+03
LOAC2	JNID/IL	3.57E-07	8.14E-04	3.34E-03	1.53E-02	Gamma	0.300	8.982E+01

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.1.2 Loss of Vital DC Bus (LODC)

7.1.2.1 Initiating Event Description

From Reference 3, the Loss of Vital DC Bus (LODC) initiating event is any sustained de-energization of a safety-related bus due to the inability to connect to any of the normal or alternative electrical power supplies. The bus must be damaged or its power source unavailable for reasons beyond an open, remotely-operated feeder-breaker from a live power source. Examples include supply cable grounds, failed insulators, damaged disconnects, transformer deluge actuations, and improper uses of grounding devices.

7.1.2.2 Data Collection and Review

Data for the LODC baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LODC is 1988–2010. (With only one event, the entire period is used for the baseline.) Figure 7-2 shows the trend of the full LODC data set and the baseline period used in this analysis. The RADS database was used to collect the LODC data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period.

The LODC results shown here in **Error! Not a valid bookmark self-reference.** and Table 7-4 include a calculated value to adjust the LODC frequency to use in PRA models where the LODC initiator can be caused by more than a single DC bus. The calculated value (LODC2) consists of dividing the mean by two and recalculating the uncertainty using an alpha parameter of 0.3.

Table 7-3 summarizes the data obtained from RADS and used in the LODC analysis.

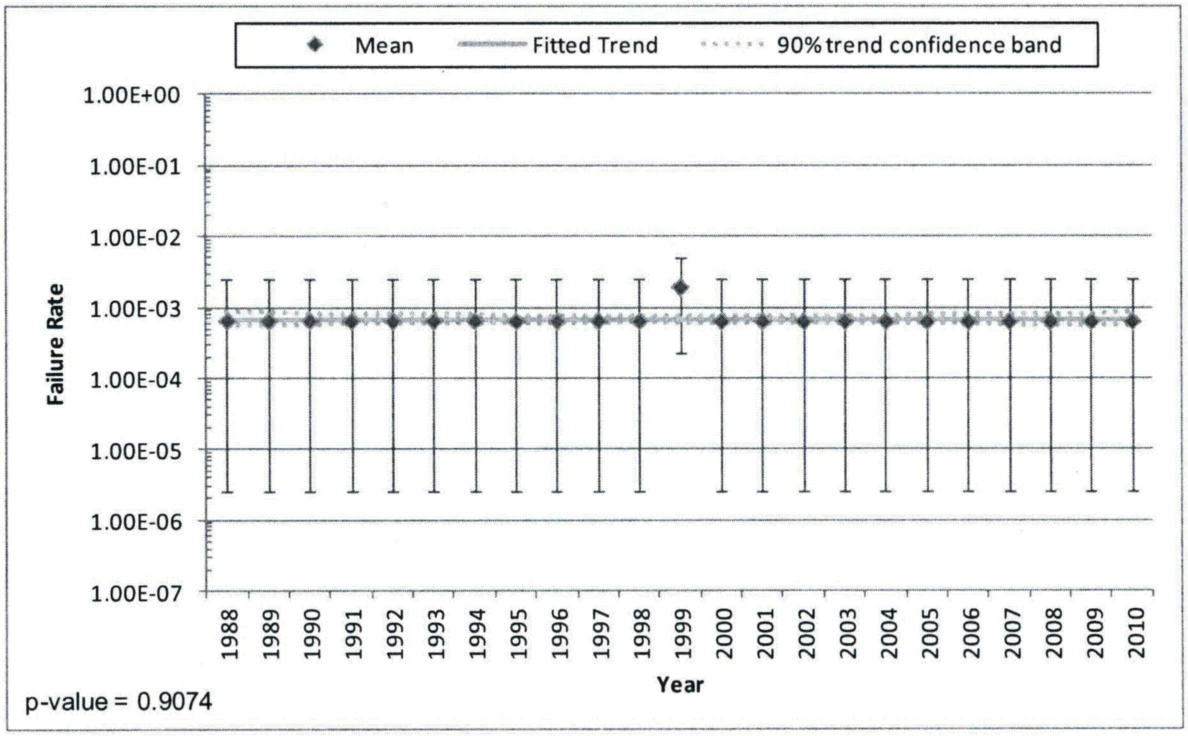

Figure 7-2. LODC trend plot.

The LODC results shown here in **Error! Not a valid bookmark self-reference.** and Table 7-4 include a calculated value to adjust the LODC frequency to use in PRA models where the LODC initiator can be caused by more than a single DC bus. The calculated value (LODC2) consists of dividing the mean by two and recalculating the uncertainty using an alpha parameter of 0.3.

Table 7-3. LODC frequency data for baseline period.

	Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
	Events	Reactor Critical Years (rcry)			
LODC	1	2035.7	1988-2010	114	0.9%
LODC2	1	2035.7	1988-2010	114	0.9%

7.1.2.3 Industry-Average Baselines

Table 7-4 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-4. Selected industry distribution of λ for LODC.

IE	Source	5%	Median	Mean	95%	Distribution		
						Type	α	β
LODC	JNID/IL	8.64E-05	5.81E-04	7.37E-04	1.92E-03	Gamma	1.500	2.036E+03
LODC2	JNID/IL	3.94E-08	8.98E-05	3.69E-04	1.69E-03	Gamma	0.300	8.141E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.2 *Loss of Safety-Related Cooling Water*

7.2.1 Loss of Emergency Service Water (LOESW)

7.2.1.1 Initiating Event Description

From Reference 3, the Loss of Service Water System (LOSWS) initiating event is a total loss of service water flow. The service water system (SWS) can be an open-cycle or a closed-cycle cooling water system. An open-cycle SWS takes suction from the plant's ultimate heat sink (e.g., the ocean, bay, lake, pond or cooling towers), removes heat from safety-related systems and components, and discharges the water back to the ultimate heat sink. A closed-cycle or intermediate SWS removes heat from safety-related equipment and discharges the heat through a heat exchanger to an open-cycle service water system.

For this report, the definition was specialized to include only emergency service water (ESW) systems. Therefore, the initiating event is Loss of Emergency Service Water (LOESW).

7.2.1.2 Data Collection and Review

Data for the LOESW baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOESW is 1988–2010. (There were no events.) The RADS database was used to collect the LOESW data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-5 summarizes the data obtained from RADS and used in the LOESW analysis.

Table 7-5. LOESW frequency data.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	2035.7	1988-2010	114	0.0%

7.2.1.3 Industry-Average Baselines

Table 7-6 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-6. Selected industry distribution of λ for LOESW.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	9.66E-07	1.12E-04	2.46E-04	9.44E-04	Gamma	0.500	2.036E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.2.2 Partial Loss of Emergency Service Water (PLOESW)

7.2.2.1 Initiating Event Description

From Reference 3, the Partial Loss of Service Water System (PLOSWS) initiating event is a loss of one train of a multiple train system or partial loss of a single train system that impairs the ability of the system to perform its function. Examples include pump cavitation, strainer fouling, and piping rupture.

This category does not include loss of a redundant component in a SWS as long as the remaining, similar components provide the required level of performance. For example, a loss of a single SWS pump is not classified as a PLOSWS as long as the remaining operating or standby pumps can provide the required level of performance. A loss of service water to a single component in another system because of a blockage or incorrect line-up that does not affect the cooling to other components serviced by the train is not included under this category, but is instead classified as a failure of the system that the single component serves.

For this report, the definition was specialized to include only emergency service water (ESW) systems; therefore, the initiating event is Partial Loss of Emergency Service Water (PLOESW).

7.2.2.2 Data Collection and Review

Data for the PLOESW baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for PLOESW is 1988–2010. (With only four events, the entire period is chosen for the baseline.) Figure 7-3 shows the trend of the full PLOESW data set and the baseline period used in this analysis. The RADS database was used to collect the PLOESW data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-7 summarizes the data obtained from RADS and used in the PLOESW analysis.

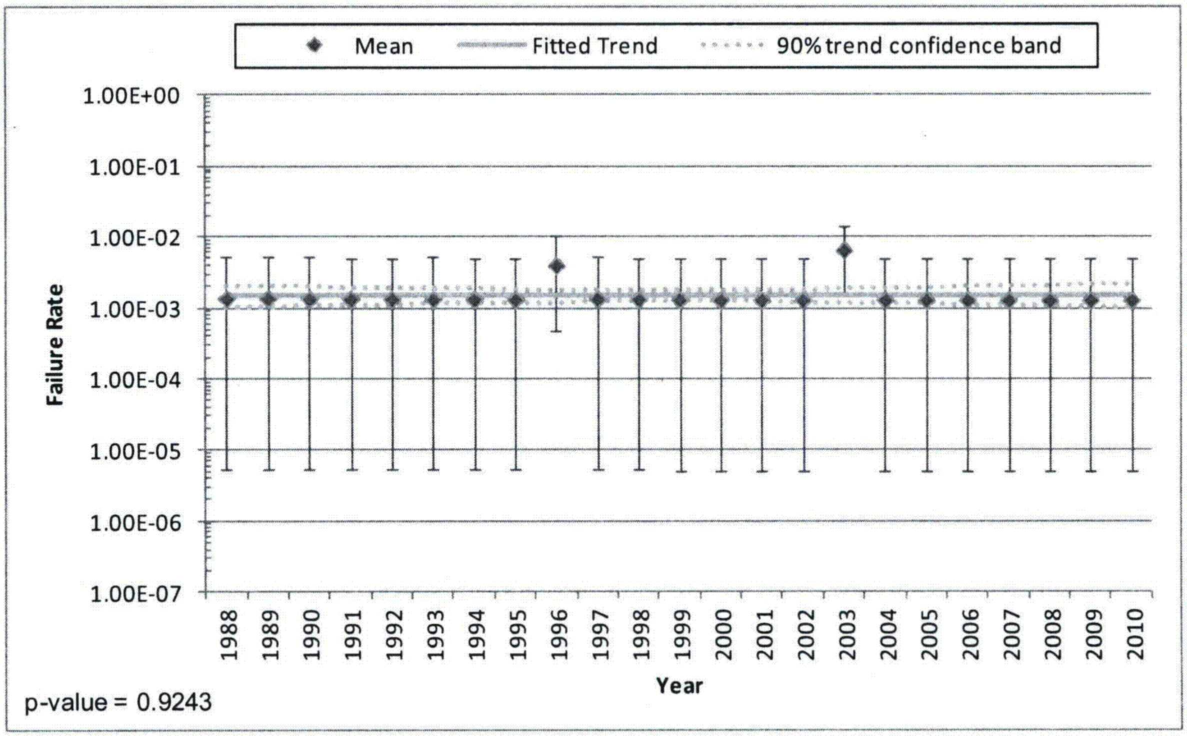

Figure 7-3. PLOESW trend plot.

Table 7-7. PLOESW frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
3	2035.7	1988-2010	114	2.6%

7.2.2.3 Industry-Average Baselines

Table 7-8 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-8. Selected industry distribution of λ for PLOESW.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	5.32E-04	1.56E-03	1.72E-03	3.46E-03	Gamma	3.500	2.036E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.2.3 Loss of Component Cooling Water (LOCCW)

7.2.3.1 Initiating Event Description

From Reference 3, the Loss of Component Cooling Water (LOCCW) initiating event is a complete loss of the component cooling water (CCW) system. CCW is a closed-cycle cooling water system that removes heat from safety-related equipment and discharges the heat through a heat exchanger to an open-cycle service water system.

7.2.3.2 Data Collection and Review

Data for LOCCW baselines were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOCCW is 1988–2010. (No events were identified, so the entire period was chosen for the baseline.) The RADS database was used to collect the LOCCW data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-9 summarizes the data obtained from RADS and used in the LOCCW analysis.

Table 7-9. LOCCW frequency data.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
0	2035.7	1988-2010	114	0.0%

7.2.3.3 Industry-Average Baselines

Table 7-10 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-10. Selected industry distribution of λ for LOCCW.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	9.66E-07	1.12E-04	2.46E-04	9.44E-04	Gamma	0.500	2.036E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.2.4 Partial Loss of Component Cooling Water System (PLOCCW)

7.2.4.1 Initiating Event Description

From Reference 3, the Partial Loss of Component Cooling Water System (PLOCCW) initiating event is a loss of one train of a multiple train system or partial loss of a single train system that impairs the ability of the system to perform its function. Examples include pump cavitation, filter fouling, and piping rupture. The component cooling water (CCW) is a closed-cycle cooling water system that removes heat from safety-related equipment and discharges the heat through a heat exchanger to an open-cycle service water system.

These categories do not include a loss of a redundant component in a CCW as long as the remaining, similar components provide the required level of performance. For example, a loss of a single CCW pump is not classified as a partial loss of a CCW as long as the remaining operating or standby pumps can provide the required level of performance. A loss of CCW to a single component in another system because of a blockage or incorrect line-up that does not affect the cooling to other components serviced by the train is not included under this category, but is instead classified as a failure of the system that the single component serves.

7.2.4.2 Data Collection and Review

Data for the PLOCCW baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for PLOCCW is 1988–2010. (With only one event, the entire period is chosen for the baseline.) Figure 7-4 shows the trend of the full PLOCCW data set and the baseline period used in this analysis. The RADS database was used to collect the PLOCCW data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-11 summarizes the data obtained from RADS and used in the PLOCCW analysis.

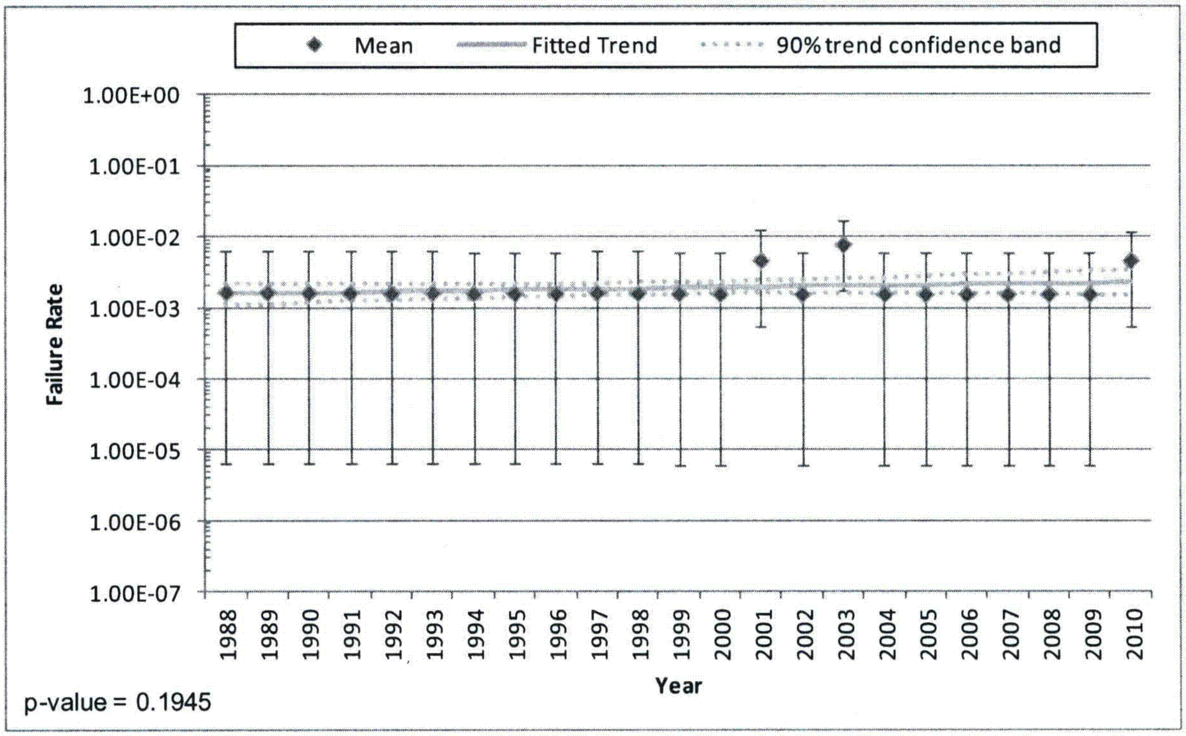

Figure 7-4 PLOCCW trend plot.

Table 7-11. PLOCCW frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
4	2035.7	1988-2010	114	3.5%

7.2.4.3 Industry-Average Baselines

Table 7-12 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-12. Selected industry distribution of λ for PLOCCW.

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	8.17E-04	2.05E-03	2.21E-03	4.16E-03	Gamma	4.500	2.036E+03

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.3 Loss of Instrument Control Air

7.3.1 Loss of Instrument Air at Boiling Water Reactors (LOIA (BWR))

7.3.1.1 Initiating Event Description

From Reference 3, the Loss of Instrument Air at Boiling Water Reactors (LOIA (BWR)) initiating event is a total or partial loss of an instrument or control air system that leads to a reactor trip or occurs shortly after the reactor trip. Examples include ruptured air headers, damaged air compressors with insufficient backup capability, losses of power to air compressors, line fitting failures, improper system line-ups, and undesired operations of pneumatic devices in other systems caused by low air header pressure.

7.3.1.2 Data Collection and Review

Data for the LOIA (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOIA (BWR) is 1991–2010. Figure 7-5 shows the trend of the full LOIA (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the LOIA (BWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period.

Table 7-13 summarizes the data obtained from RADS and used in the LOIA (BWR) analysis.

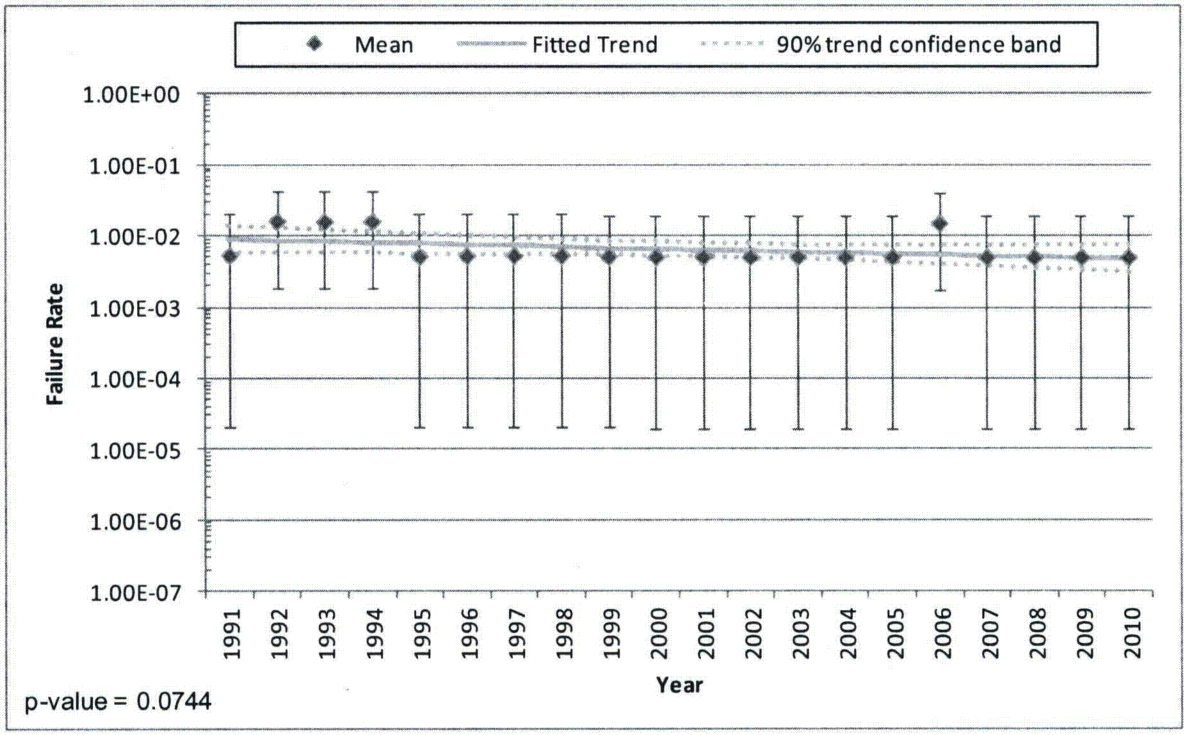

Figure 7-5. LOIA (BWR) trend plot.

Table 7-13. LOIA (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
4	600.4	1991-2010	37	10.8%

7.3.1.3 Industry-Average Baselines

Table 7-14 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-14. Selected industry distribution of λ for LOIA (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
JNID/IL	2.77E-03	6.95E-03	7.49E-03	1.41E-02	Gamma	4.500	6.004E+02

Note – JNID/IL is a Jeffrey's noninformative distribution at the industry level. Percentiles and the mean have units of events/rcry. The units for β are rcry.

7.3.2 Loss of Instrument Air at Pressurized Water Reactors (LOIA (PWR))

7.3.2.1 Initiating Event Description

From Reference 3, the Loss of Instrument Air at Pressurized Water Reactors (LOIA (PWR)) initiating event is a total or partial loss of an instrument or control air system that leads to a reactor trip or occurs shortly after the reactor trip. Examples include ruptured air headers, damaged air compressors with insufficient backup capability, losses of power to air compressors, line fitting failures, improper system line-ups, and undesired operations of pneumatic devices in other systems caused by low air header pressure.

7.3.2.2 Data Collection and Review

Data for the LOIA (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for LOIA (PWR) is 1997–2010. Figure 7-6 shows the trend of the full LOIA (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the LOIA (PWR) data for the baseline period. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 7-15 summarizes the data obtained from RADS and used in the LOIA (PWR) analysis.

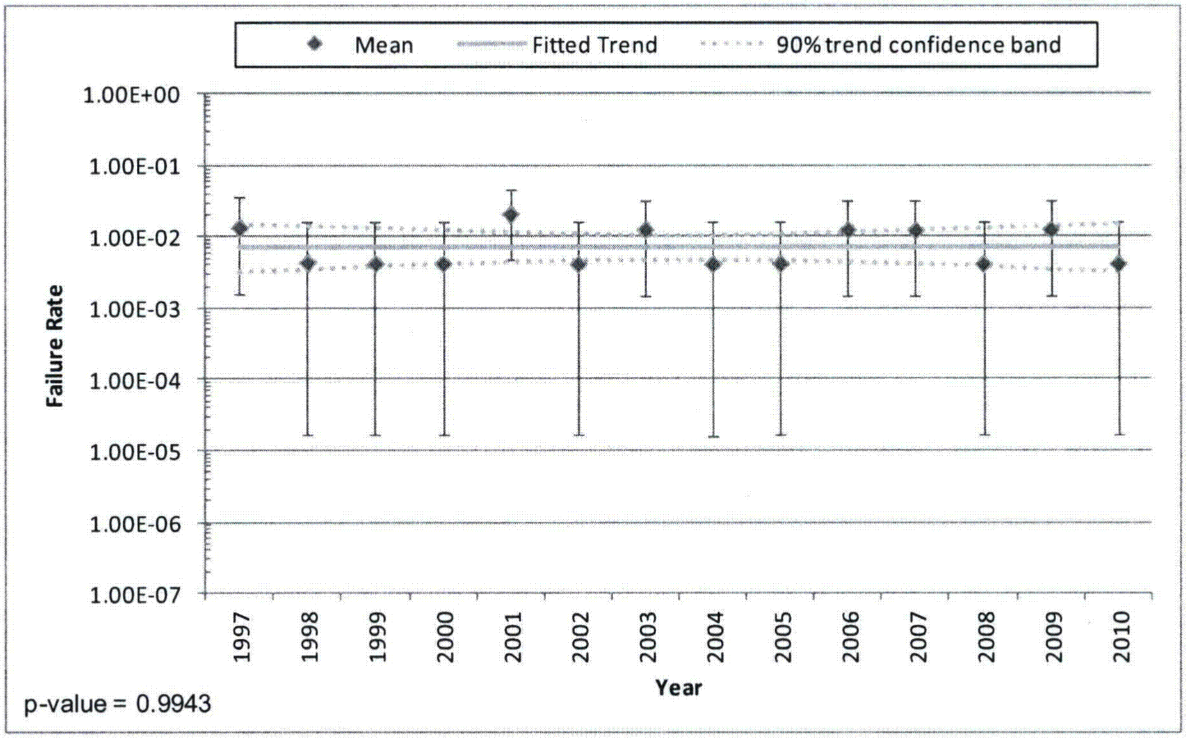

Figure 7-6. LOIA (PWR) trend plot.

Table 7-15. LOIA (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
7	856.8	1997-2010	70	8.6%

7.3.2.3 Industry-Average Baselines

Table 7-16 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 7-16. Selected industry distribution of λ for LOIA (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	6.36E-06	2.84E-03	8.22E-03	3.47E-02	Gamma	0.383	4.662E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

8 Transient

The general transient categories result in automatic or manual reactor trips but do not degrade safety system response.

8.1 General Transient at Boiling Water Reactors (TRAN (BWR))

8.1.1 Initiating Event Description

From Reference 3, the General Transient at Boiling Water Reactors (TRAN (BWR)) initiating event is a general transient that results in automatic or manual reactor trips but does not degrade safety system response.

8.1.2 Data Collection and Review

Data for the TRAN (BWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for TRAN (BWR) is 1997–2010. Figure 8-1 shows the trend of the full TRAN (BWR) data set and the baseline period used in this analysis. The RADS database was used to collect the TRAN (BWR) data for the baseline period. Only initial plant fault events as defined in Reference 3 were used. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period.

Table 8-1 summarizes the data obtained from RADS and used in the TRAN (BWR) analysis.

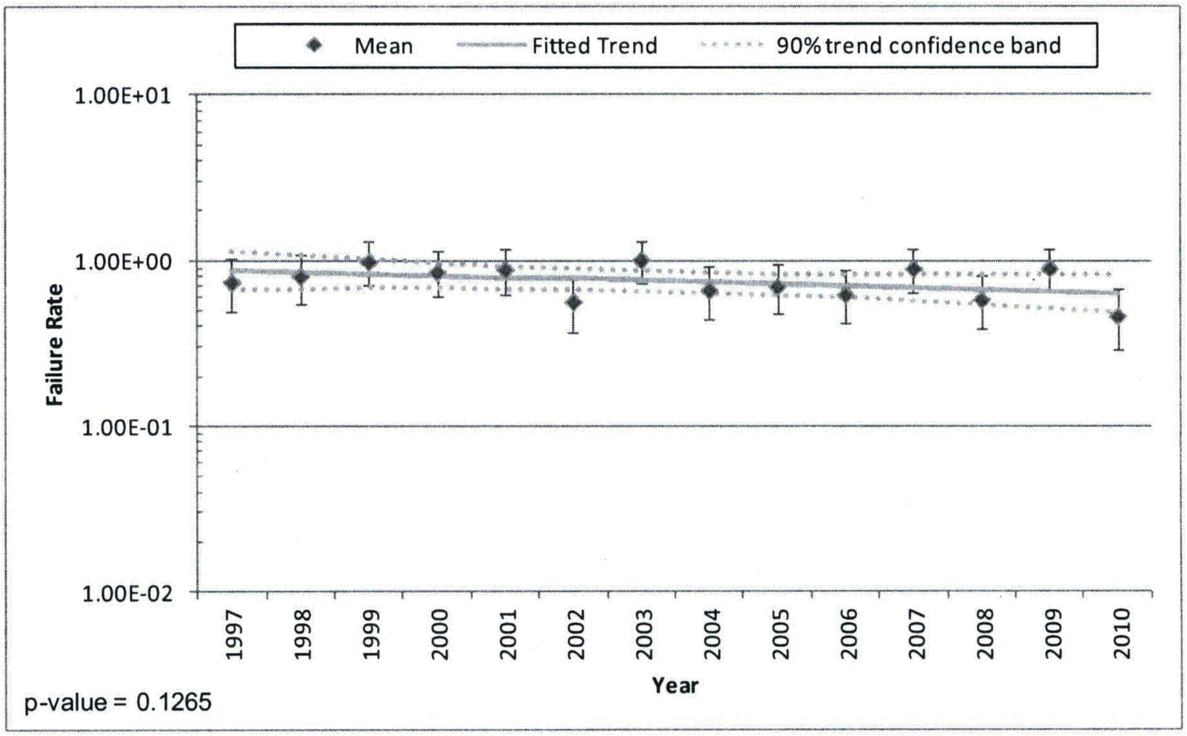

Figure 8-1. TRAN (BWR) trend plot.

Table 8-1. TRAN (BWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
332	437.3	1997-2010	36	97.2%

8.1.3 Industry-Average Baselines

Table 8-2 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 8-2. Selected industry distribution of λ for TRAN (BWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	5.11E-01	7.50E-01	7.62E-01	1.06E+00	Gamma	21.030	2.759E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

8.2 *General Transient at Pressurized Water Reactors (TRAN (PWR))*

8.2.1 Initiating Event Description

From Reference 3, the General Transient at Boiling Water Reactors (TRAN (PWR)) initiating event is a general transient that results in automatic or manual reactor trips but does not degrade safety system response.

8.2.2 Data Collection and Review

Data for the TRAN (PWR) baseline were obtained from the IEDB, as accessed using RADS. Using the process outlined in Section D.1.2 of Reference 6, the optimized baseline period for TRAN (PWR) is 1998–2010. Figure 8-2 shows the trend of the full TRAN (PWR) data set and the baseline period used in this analysis. The RADS database was used to collect the TRAN (PWR) data for the baseline period. Only initial plant fault events as defined in Reference 3 were used. Results include total number of events and total reactor critical years (rcry's) for the U.S. commercial nuclear power plant industry. These results also include the individual plant results for the same period. Table 8-3 summarizes the data obtained from RADS and used in the TRAN (PWR) analysis.

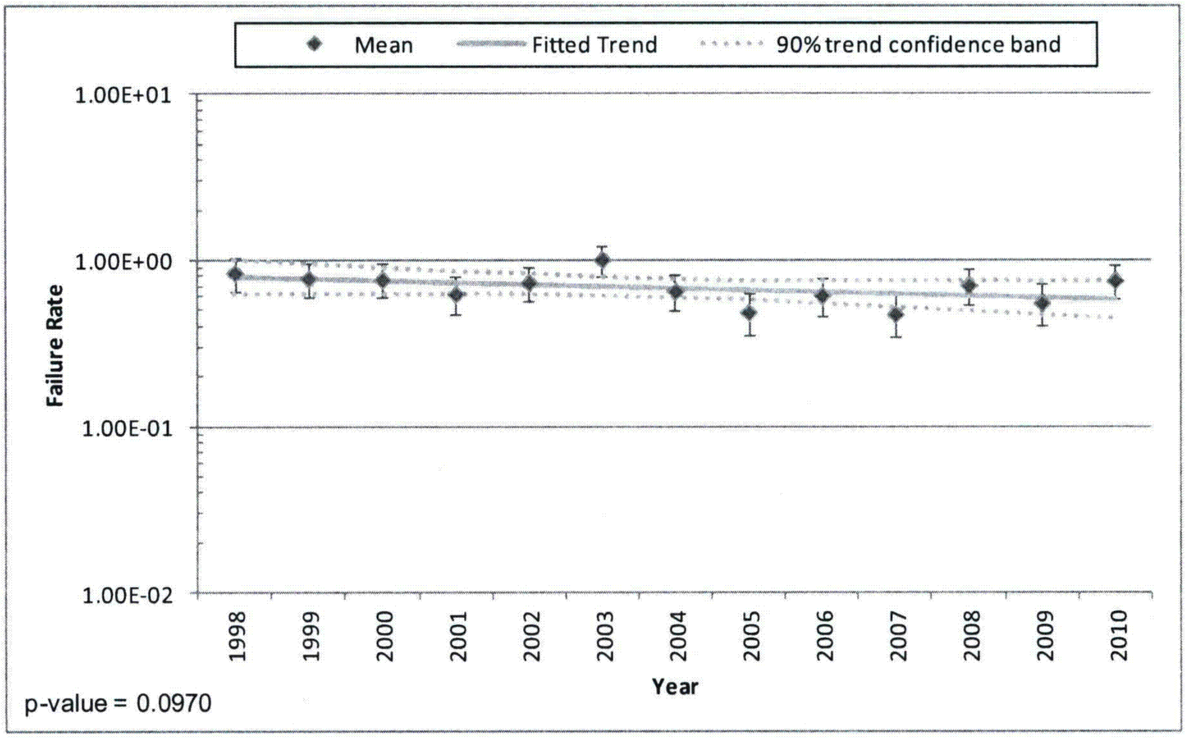

Figure 8-2. TRAN (PWR) trend plot.

Table 8-3. TRAN (PWR) frequency data for baseline period.

Data After Review		Baseline Period	Number of Plants	Percent of Plants with Events
Events	Reactor Critical Years (rcry)			
553	803.9	1998-2010	69	100.0%

8.2.3 Industry-Average Baselines

Table 8-4 lists the industry-average frequency distribution. This industry-average frequency does not account for any recovery.

Table 8-4. Selected industry distribution of λ for TRAN (PWR).

Source	5%	Median	Mean	95%	Distribution		
					Type	α	β
EB/PL/KS	3.47E-01	6.62E-01	6.90E-01	1.13E+00	Gamma	8.185	1.187E+01

Note – EB/PL/KS is an empirical Bayes analysis at the plant level with the Kass-Steffey adjustment. Percentiles and the mean have units of events/rcry. The units for β are rcry.

9 References

1. U.S. Nuclear Regulatory Commission, "Reactor Operational Experience Results and Databases, Initiating Events," http://nrcoe.inel.gov/results.

2. D.M. Rasmuson, T.E. Wierman, and K.J. Kvarfordt, "An Overview of the Reliability and Availability Data System (RADS)," *International Topical Meeting on Probabilistic Safety Analysis PSA '05*, American Nuclear Society, Inc., 2005.

3. J.P. Poloski et al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987–1995*, U.S. Nuclear Regulatory Commission, NUREG/CR-5750, February 1999.

4. S.A. Eide et al., *Reevaluation of Station Blackout Risk at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, NUREG/CR-6890, December 2005.

5. R. Tregoning, L. Abramson, and P. Scott, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process*, U.S. Nuclear Regulatory Commission, NUREG-1829 (draft), June 2005.

6. S.A. Eide et al., *Industry-Average Performance for Components and Initiating Events at U.S. commercial Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, NUREG/CR-6928, January 2007.

Catawba Units 1 & 2 Power History

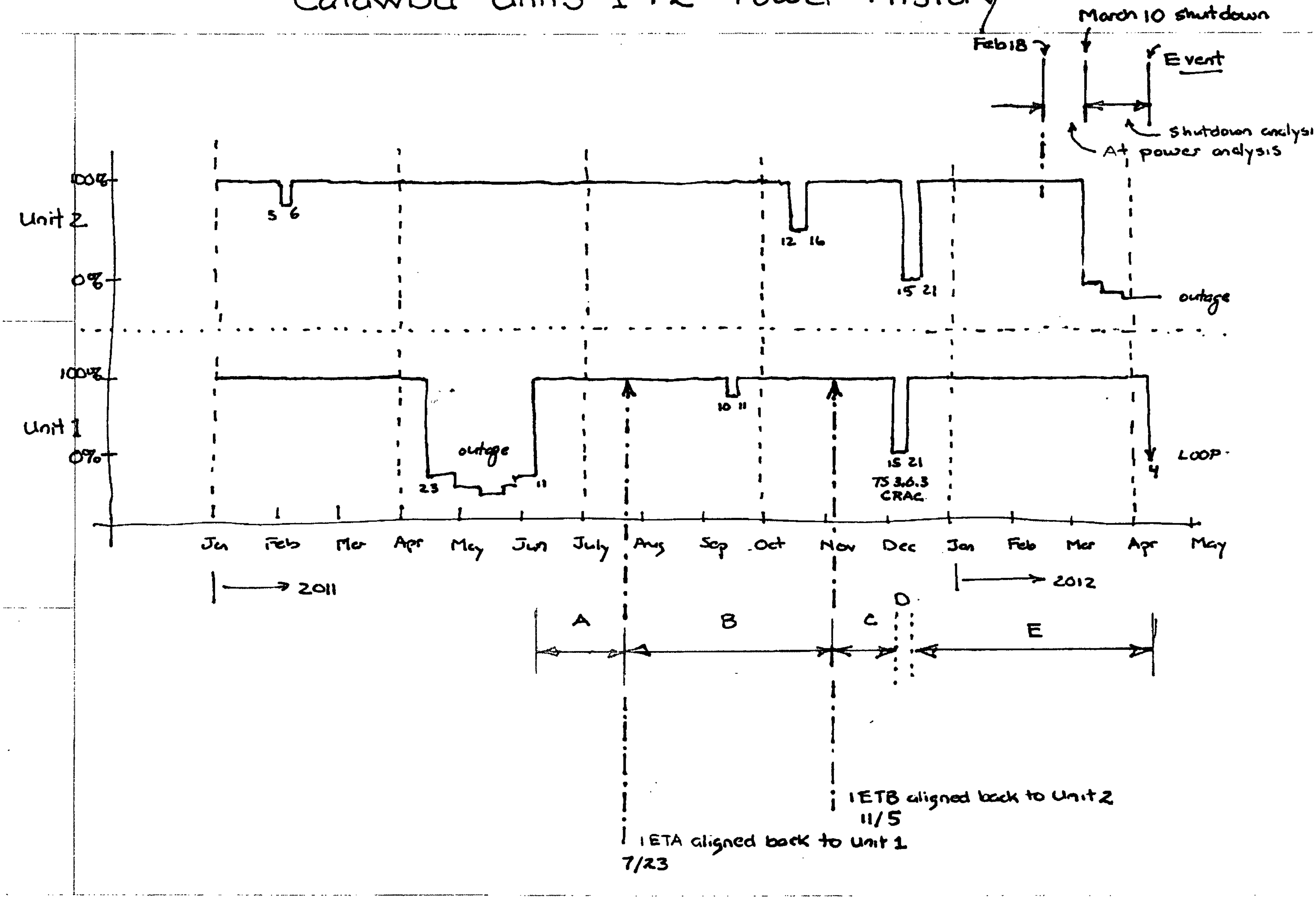

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Table 1- SDP PHASE 1 SCREENING WORKSHEET FOR ALL CORNERSTONES
Reference/Title (LER #, Inspection Report #, etc): 05000413/2012009, 05000414/2012009
Performance Deficiency (concise statement clearly stating deficient licensee performance): The licensee failed to follow the requirements of EDM 141 for providing appropriate design information to the vendor for programming the Zone G digital processors.
Factual Description of Condition (statement of <u>facts</u> known about the condition that resulted from the performance deficiency, <u>without</u> hypothetical failures included.) Explain why issue is more than minor: Unit 2 was cross-tied through Unit 1 prior to the Unit 2 outage. 2ETA aligned on 2/4/12, 2ETB aligned on 2/18/12. Due to the Zone G modification performed on Unit 1, Unit 2 was susceptible to a loss of an offsite power source for any event or transient on Unit 1 from 100% power which results in a reactor/turbine trip.
System(s)/Train(s) Degraded by Condition or Programmatic Weakness (note that the safety functions affected must be those identified in the Site Specific Risk-Informed Inspection Notebooks): Offsite Power - Consisting of two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System.
Licensing Basis Function of System(s)/Train(s) or Program: An offsite power system and an onsite power system are provided for each unit at the Catawba Nuclear Station to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safety Features Systems during abnormal and accident conditions. Each Catawba Unit is connected to a common 230kV switchyard and thereby to the Duke 230kV transmission system via two separate and independent transmission lines.
Other Safety Function of System(s)/Train(s): N/A
Maintenance Rule Category (check one): _X_ risk-significant ____ non risk-significant
Time condition existed or is assumed to have existed: Condition existed from February 4, 2012, when 2ETA was cross-tied through Unit 1 for offsite power, until April 4, 2012, when the event occurred. (Unit 2 shutdown for refueling outage on March 10, 2012)

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Table 2 - CORNERSTONES AND FUNCTIONS DEGRADED AS A RESULT OF DEFICIENCY
(✔) Check the appropriate boxes

INITIATING EVENTS CORNERSTONE	MITIGATION SYSTEMS CORNERSTONE	BARRIERS CORNERSTONE
❐ Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ❐ Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ❐ Fire initiator contributor (e.g., transient loadings and combustibles, hotwork) ❐ Internal/external flooding initiator contributor	☒ Core Decay Heat Removal Degraded ☒ Short Term Heat Removal Degraded ☒ Primary (e.g., Safety Inj, [main feedwater, HPCI, and RCIC - BWR only]) _x_ High Pressure _x_ Low Pressure ❐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ❐ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ❐ Reactivity Control Degraded ❐ Seismic/Fire/Flood/Severe Weather Protection Degraded	❐ RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). Note: all other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. ❐ Containment Barrier Degraded ❐ Reactor Containment Degraded ___ Actual Breach or Bypass ___ Heat Removal, Hydrogen or Pressure Control Degraded ❐ Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ❐ Fuel Cladding Barrier Degraded ❐ Spent Fuel Pool ❐ Spent Fuel Pool Boiling ❐ Fuel Handling ❐ Spent Fuel Pool Inventory
EMERGENCY PREPAREDNESS CORNERSTONE	**OCCUPATION RADIATION SAFETY CORNERSTONE**	**PUBLIC RADIATION SAFETY CORNERSTONE**
❐ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard ❐ Actual Event Implementation Problem	❐ ALARA Planning or Work Controls ❐ Exposure or Over-exposure problem ❐ Ability to Assess Dose Compromised	❐ Radioactive Effluent Release Program ❐ Radioactive Environmental Monitoring Program ❐ Radioactive Material Control Program ❐ Transportation or Part 61
SECURITY CORNERSTONE		
❐ Findings identified under the IMC-2201, Security and Safeguards Inspection Program		

Table 3a - SDP PHASE 1 SCREENING WORKSHEET FOR EMERGENCY PREPAREDNESS, OCCUPATIONAL & PUBLIC RADIATION, AND SECURITY CORNERSTONES
IF the finding is in the licensee's: 1. emergency preparedness area, **THEN STOP. Go to** IMC 0609, Appendix B. 2. occupational radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix C. 3. public radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix D. 4. security area, **THEN STOP. Go to** IMC 0609, Appendix E.

Table 3b - SDP PHASE 1 SCREENING WORKSHEET FOR INITIATING EVENTS, MITIGATION SYSTEMS, AND BARRIERS CORNERSTONES
IF the finding affects: 1. fire protection defense-in-depth strategies involving: detection, suppression (equipment for both manual and automatic), barriers, fire prevention and administrative controls, and post fire safe shutdown systems, **THEN STOP. Go to** IMC 0609, Appendix F. Issues related to performance of the fire brigade are not included in Appendix F and require NRC management review using Appendix M. 2. the safety of a reactor during refueling outages, forced outages, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated, **THEN STOP. Go to** IMC 0609, Appendix G. 3. the operator licensing requalification program or simulator fidelity, **THEN STOP. Go to** IMC 0609, Appendix I. 4. steam generator tube integrity, **THEN STOP. Go to** IMC 0609, Appendix J. 5. the licensee's assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control," **THEN STOP. Go to** IMC 0609, Appendix K. 6. SSCs where existing SDP guidance is not adequate to provide reasonable estimates of the findings significance within the established SDP timeliness goal of 90 days, **THEN STOP. Go to** IMC 0609, Appendix M. 7. the safety of an operating reactor, **THEN IDENTIFY** the degraded cornerstone(s): □ Initiating Event □ Mitigation Systems □ RCS Barrier (e.g., PTS issues) □ Fuel Barrier □ Containment Barriers **CONTINUE** to the appropriate column in Table 4a - Characterization Worksheet. NOTE: When assessing the significance of a finding affecting multiple cornerstones, the finding should be assigned to the cornerstone that best reflects the dominant risk of the finding.

Table 4a - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES

Initiating Events Cornerstone	Mitigation Systems Cornerstone	RCS or Fuel Barrier	Containment Barrier
LOCA Initiators 1. Assuming worst case degradation, would the finding result in exceeding the Tech Spec limit for any RCS leakage or could the finding have likely affected other mitigation systems resulting in a total loss of their safety function. ☐ **If YES →Stop. Go to Appendix A.** ☐ If NO, screen as Green. Transient Initiators 1. 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→Stop. Go to Appendix A.** ☐ If NO, screen as Green. External Event Initiators 1. 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 confirmed not to result in loss of operability or functionality.[1] ☐ **If YES, screen as Green.** ☒ If NO, continue. 2. Does the finding represent a loss of system safety function? ☒ **If YES →Stop. Go to Appendix A.** ☐ If NO, continue. 3. Does the finding represent actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time? ☐ **If YES → Stop. Go to Appendix A.** ☐ 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 → Stop. Go to Appendix A.** ☐ If NO, continue. 5. Does the finding screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event, using the criteria on page 5 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.	RCS Barrier (e.g., pressurized thermal shock issues) ☐ **Stop. Go to Phase 3.** Fuel Barrier ☐ Stop. Screen as Green. Spent Fuel Pool Issues 1. Does the finding result in loss of cooling to the spent fuel pool, whereby operator or equipment failures could preclude restoration of cooling prior to pool boiling? ☐ **If YES** → Stop. Go to **Appendix M.** ☐ If NO, continue. 2. Does the finding result from fuel handling errors that caused damage to fuel clad integrity or a dropped assembly (includes ISFSI)? ☐ **If YES** → Stop. Go to **Appendix M**. ☐ If NO, continue. 3. Does the finding result in a loss of spent fuel pool inventory greater than 10% of SFP volume? ☐ **If YES** → Stop. Go to **Appendix A**. ☐ If NO, screen as Green.	1. Does the finding only represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, or SBGT system (BWR)? ☐ **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 → Stop. Go to Phase 3.** ☐ If NO, continue. 3. Does the finding represent an actual open pathway in the physical integrity of reactor containment (valves, airlocks, containment isolation system (logic and instrumentation), and heat removal components? ☐ **If YES → Stop. Go to Appendix H.** ☐ If NO, continue. 4. Does the finding involve an actual reduction in function of hydrogen ignitors in the reactor containment? ☐ **If YES → Stop. Go to Appendix H.** ☐ If NO, screen as Green.

[1] per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment."

Table 4b - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES
Seismic, 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)?

   - ☐ **If YES** ➛ continue to question 2
   - ☐ If NO ➛ skip to question 3

2. If the equipment or safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of this 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 **two or more** Trains of a multi-train safety system or function;

   c) would degrade one or more Trains of a system that supports a safety system or function.

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

3. Does the finding involve the total 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, flooding, or severe weather event)?

   - ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet
   - ☐ If NO, screen as Green

Result of Phase 1 screening process:

☐ **Screen as Green** ☒ **Go to Phase 2** ☐ **Go to Phase 3**

Important Assumptions:
Due to Zone G modification, any transient on Unit 1 from 100% power which causes a reactor/turbine trip would cause a loss of offsite power. (Loss of one offsite circuit from 2/4/12 to 2/18/12. LOOP from 2/18/12 to 3/10/12)
Offsite Power considered a "mitigating system" in this analysis rather than an initiator since it supplies the Onsite Essential Auxiliary Power distribution system and associated mitigating systems.
The loss of offsite power represents a loss of system safety function.

Performed by: Eric Stamm Date: 6/19/12

Table 3.7 SDP Worksheet for Catawba Nuclear Station, Units 1 and 2 — Loss of Offsite Power (LOOP) [1, 7]

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Emergency AC Power (EAC)	1/2 EDGs (1 multi-train system)
Turbine-Driven AFW Pump (TDAFW)	1/1 TDAFW train to 2/4 SGs with manual control and throttling of the flow (1 ASD train) [6]
Safe Shutdown Facility (SSF)	One diesel generator and the makeup pump with associated support injecting into 4/4 RCP seals (operator action = 1) [2]
RCP Seal Integrity (SEAL)	RCP Seals do not fail in the first 13-15 minutes (Credit = 1)
TDAFW Sump Pump (WL)	Failure of 1/1 sump pump for TDAFW pit (1 train)
Recovery of AC Power in < 2 Hours (REC2)	Recovery of AC source in less than 2 hours [3] (operator action = 1)
Secondary Heat Removal (AFW2)	1/2 MDAFW trains to 2/4 SGs (1 multi-train system)
Early Inventory, High Pressure Injection (EIHP)	1/2 NV trains injecting into 3/4 loops and 1/2 NI trains injecting into 4/4 loops (1 multi-train system)
Primary Heat Removal, Feed/Bleed (FB)	1/3 PORVs open for Feed and Bleed (operator action = 2) [4]
High Pressure Recirculation (HPR)	1/2 NV trains or 1/2 NI trains taking suction from 1/2 LPSI (RHR) trains (operator action = 3) [5]

Circle Affected Functions		IEL	Remaining Mitigation Capability Rating for Each Affected Sequence	Recovery Credit	Results	LERF Factor
1 LOOP - TDAFW - AFW2 - HPR (4) **2 + 1 + 3 + 3**	**9**	0	1 + 3 + 3	1	8	**0**
2 LOOP - TDAFW - AFW2 - FB (5) **2 + 1 + 3 + 2**	**8**	0	1 + 3 + 2	1	7	**0**
3 LOOP - TDAFW - AFW2 - EIHP (6) **2 + 1 + 3 + 3**	**9**	0	1 + 3 + 3	1	8	**0**
4 LOOP - EAC - WL - REC2 (9, 12) **2 + 3 + 2 + 1**	**8**	0	3 + 2 + 1	1	7	**1**
5 LOOP - EAC - SSF - SEAL - HPR (14) (AC recovered in 2 hours) **2 + 3 + 1 + 1 + 3**	**10**	0	3 + 1 + 1 + 3	1	9	**0**

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6 LOOP - EAC - SSF - SEAL - EIHP (15) (AC recovered in 2 hours) 2 + 3 + 1 + 1 + 3	10	0	3 + 1 + 1 + 3	1	9	0
7 LOOP - EAC - SSF - SEAL - REC2 (16) 2 + 3 + 1 + 1 + 1	8	0	3 + 1 + 1 + 1	1	7	1
8 LOOP - EAC - TDAFW - HPR (18) (AC recovered in 2 hours) 2 + 3 + 1 + 3	9	0	3 + 1 + 3	1	8	0
9 LOOP - EAC - TDAFW - FB (19) (AC recovered in 2 hours) 2 + 3 + 1 + 2	8	0	3 + 1 + 2	1	7	0
10 LOOP - EAC - TDAFW - EIHP (20) (AC recovered in 2 hours) 2 + 3 + 1 + 3	9	0	3 + 1 + 3	1	8	0
11 LOOP - EAC - TDAFW - REC2 (21) 2 + 3 + 1 + 1	7	0	3 + 1 + 1	1	6	1

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

IEL = 0 for LOOP since LOOP would have occurred for an event.

Recovery Credit = 1 as it is reasonable offsite power would have been restored within 2 hours (environmental conditions, procedures, training, equip OK).

SSF = 1 for full credit although SSF diesel on achieved 2/3 rated voltage during event (Still awaiting results of licensee's degraded voltage testing).

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 PRA assumes SG dryout in about 20 to 30 minutes. It is therefore assumed that if the AC is recovered in less than 15 minutes, neither seal leakage nor SG dryout has occurred.
2. The PRA uses a human error probability (HEP) of about 8.5E-2 which is considered here as an operator action with a credit of 1.

3. In SBO scenarios, it is assumed that it takes approximately 2 hours after the RCP seal LOCA, or total loss of secondary cooling, for the core damage to occur (core becomes uncovered). The recovery of AC power in 2 hours is in a range of 4.71E-1 to 2.2E-2 depending on all other conditions. A credit of 1 is given in this SDP worksheet.

4. The HEP for FB in the PRA is 1.2E-2.

5. The HEP for switchover to recirculation is 4.5E-3.

6. The flow for TDAFW is to be controlled locally. An operator action of 0.25 is assigned in the PRA. Extended operation of the TDAFW beyond two hours is credited as long as the SSF DG and the TDAFW sump pump fed from the SSF diesel generator is operating.

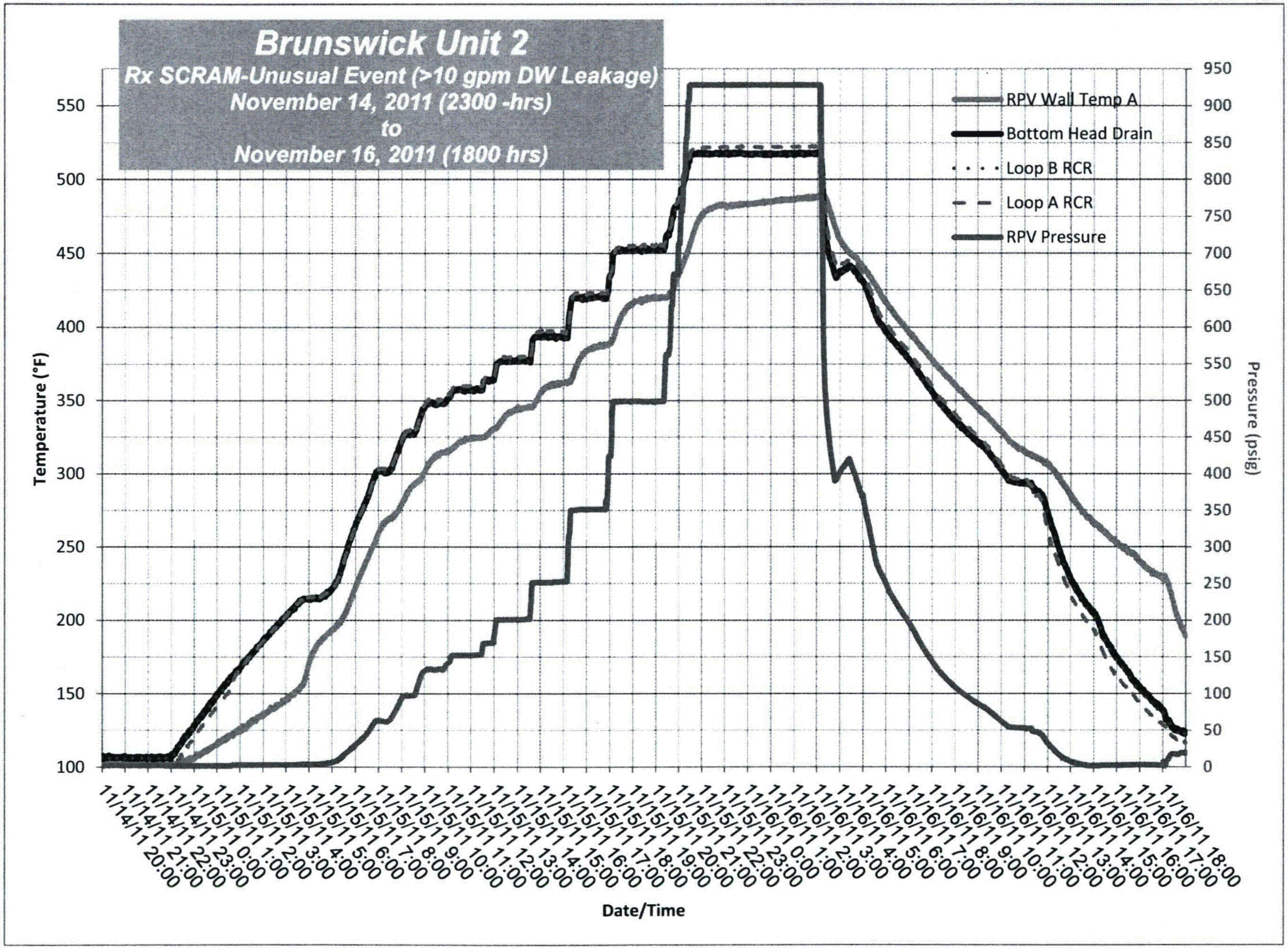
7. Alternative strategies may apply to this worksheet. See Table 2a.

Table 5 - Counting Rule Worksheet

Step	Instructions	
(1)	Enter the number of sequences with a risk significance equal to 9.	(1) 2
(2)	Divide the result of Step (1) by 3 and round down.	(2) 0
(3)	Enter the number of sequences with a risk significance equal to 8.	(3) 4
(4)	Add the result of Step (3) to the result of Step (2).	(4) 4
(5)	Divide the result of Step (4) by 3 and round down.	(5) 1
(6)	Enter the number of sequences with a risk significance equal to 7.	(6) 4
(7)	Add the result of Step (6) to the result of Step (5).	(7) 5
(8)	Divide the result of Step (7) by 3 and round down.	(8) 1
(9)	Enter the number of sequences with a risk significance equal to 6.	(9) 1
(10)	Add the result of Step (9) to the result of Step (8).	(10) 2
(11)	Divide the result of Step (10) by 3 and round down.	(11) 0
(12)	Enter the number of sequences with a risk significance equal to 5.	(12) 0
(13)	Add the result of Step (12) to the result of Step (11).	(13) 0
(14)	Divide the result of Step (13) by 3 and round down.	(14) 0
(15)	Enter the number of sequences with a risk significance equal to 4.	(15) 0
(16)	Add the result of Step (15) to the result of Step (14).	(16) 0

- If the result of Step 16 is greater than zero, then the risk significance of the inspection finding is of high safety significance (RED).
- If the result of Step 13 is greater than zero, then the risk significance of the inspection finding is at least of substantial safety significance (YELLOW).
- If the result of Step 10 is greater than zero, then the risk significance of the inspection finding is at least of low to moderate safety significance (WHITE).
- If the result of Steps 10, 13, and 16 are zero, then the risk significance of the inspection finding is of very low safety significance (GREEN).

Phase 2 Result: ☐ **GREEN** ☒ **WHITE** ☐ **YELLOW** ☐ **RED**



Brunswick Unit 2
Rx SCRAM-Unusual Event (>10 gpm DW Leakage)
November 14, 2011 (2300 -hrs)
to
November 16, 2011 (1800 hrs)
RPV Wall Temp A
Bottom Head Drain
Loop B RCR
Loop A RCR
RPV Pressure
Temperature (°F)
Pressure (psig)
Date/Time

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Enhanced Component Performance Study

Emergency Diesel Generators

1998–2010

1 INTRODUCTION

This report presents an enhanced performance evaluation of emergency diesel generators (EDGs) at U.S. commercial nuclear power plants. This report does not estimate values for use in probabilistic risk assessments (PRAs), but does evaluate component performance over time. Reference 1 (NUREG/CR-6928) reports EDG unreliability estimates using Equipment Performance and Information Exchange (EPIX) data from 1998–2002 and maintenance unavailability (UA) performance data using Mitigating Systems Performance Index (MSPI) Basis Document data from 2002–2004 for use in PRAs.

The trend evaluations in this study are based on the operating experience failure reports from fiscal year (FY) 1998 through FY 2010 as reported in EPIX. The EDG failure modes considered are failure-to-start (FTS), failure-to-load-and-run (FTLR), and failure-to-run > 1 hour (FTR>1H). EDG train maintenance unavailability data for trending are from the same time period, as reported in the Reactor Oversight Program (ROP) and the MSPI. In addition to the presentation of the component failure mode data and the UA data, an 8-hour component total unreliability is calculated and trended.

Previously, component studies relied on operating experience obtained from licensee event reports (LERs), Nuclear Plant Reliability Data System (NPRDS), and EPIX. The EPIX database (which includes as a subset the MSPI designated devices) has matured to the point where component availability and reliability can be estimated with a higher degree of assurance of accuracy. In addition, the EPIX population of data is much larger than the population used in the previous studies.

The objective of the effort for the updated component performance studies is to obtain annual performance trends of failure rates and probabilities. An overview of the trending methods, glossary of terms, and abbreviations can be found in the Overview and Reference document on the Reactor Operational Experience Results and Databases web page.

The objective of the enhanced component performance study is to present an analysis of factors that could influence the system and component trends in addition to annual performance trends of failure rates and probabilities. The factors analyzed for the EDG component are the differences in failures between all demands and actual unplanned (ESF) demands (Section 6.2), differences among manufacturers (Section 6.3), and differences among EDG ratings (Section 6.4). Statistical analyses of these differences are performed and results showing whether pooling is acceptable across these factors. In addition, engineering analyses were performed with respect to time period and failure mode (Section 6.5). The factors analyzed are: sub-component, failure cause, detection method, recovery, manufacturer, and EDG rating.

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2 SUMMARY OF FINDINGS

The results of this study are summarized in this section. Of particular interest is the existence of any statistically significant[1] increasing trends. In this update, the following highly statistically significant increasing trends were identified in the EDG results:

- EPS, industry-wide EDG FTR>1H trend. (see Figure 3)
- EPS, industry-wide EDG unreliability trend (8-hour mission). (see Figure 9)
- Frequency (events per reactor year) of FTR>1H events, EPS and HPCS EDGs (see Figure 16)

The increasing trend in the EPS EDG unreliability (Figure 9) is primarily due to the increasing trend in the greater than 1 hour failure to run events (reflected in Figure 3 and Figure 16). In 2008, the staff at the Idaho National Laboratory (INL) reviewed the EPIX data for EDGs and found that many EDG failures that were originally counted as failure to start are more correctly classified as failure to run. The results of this review are reflected in this update.

Statistically significant decreasing trends were identified in the EDG results for the following:

- The 2002 to 2010 EDG UA in the EPS EDG UA trend. (see Figure 7).

Highly statistically significant decreasing trends were identified in the EDG results for the following:

- Frequency (events per reactor year) of start demands, EPS and HPCS EDGs. (see Figure 11)
- Frequency (events per reactor year) of load and run $\leq$ 1 hour demands, EPS and HPCS EDGs (see Figure 12)

It is uncertain what leads to the decrease in EDG start and load and run demands over time since 1998. The plots show that a step change in the rates of EDG start and load and run demands starts in 2003, which is coincident with the heightened reporting required by the MSPI program.

An ongoing concern in the industry is whether industry data adequately represent standby component performance during unplanned (ESF) demands. Section 6.2 shows the results of the consistency check between industry data and ESF detected failure data for EDGs. The consistency checks using unplanned demand data indicate that the FTLR and FTR failure observations and the Total EDG unreliability are consistent with their industry-average distribution from Table 2. The EPS EDG FTS lies in the upper 95% of the predictive distribution (superior performance).

Section 6.3 shows the results of the consistency check between EDG manufacturers. One manufacturer's EPS EDG performance lies in the lower 5% (degraded performance), however, this manufacturer involves very few EPS EDGs, so the data are limited. The rest of the manufacturers lie within the 5% to 95% interval and are consistent with the industry-average performance.

Section 6.4 shows the results of the consistency check between EDG ratings. The ratings all lie within the 5% to 95% interval and are consistent with the industry-average performance.

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[1] Statistically significant is defined in terms of the 'p-value.' A p-value is a probability indicating whether to accept or reject the null hypothesis that there is no trend in the data. P-values of less than or equal to 0.05 indicate that we are 95% confident that there is a trend in the data (reject the null hypothesis of no trend.) By convention, we use the "Michelin Guide" scale: p-value < 0.05 (statistically significant), p-value < 0.01 (highly statistically significant); p-value < 0.001 (extremely statistically significant).

3 FAILURE PROBABILITIES AND FAILURE RATES

3.1 Overview

The industry-wide failure probabilities and failure rates of EDGs have been calculated from the operating experience for FTS, FTLR, and FTR>1H. The EDG data set obtained from EPIX includes EDGs in the systems listed in Table 1. Table 2 shows industry-wide failure probability and failure rate results for the EPS EDG from Reference 1. Table 3 shows the industry-wide failure probability and failure rate results for the HPCS EDG. The HPCS EDG failure probability was not fully analyzed in Reference 1 and is presented here based on the current EPIX data that has been reviewed at the INL.

Table 1. EDG systems.

System	Description	EDG Count
EPS	Emergency power supply	223
HPCS	High pressure core spray	8
	Total	231

The EDGs are assumed to operate both when the reactor is critical and during shutdown periods. The number of EDGs in operation is assumed to be constant throughout the study period. All demand types are considered—testing, non-testing, and, as applicable, emergency safeguard feature (ESF) demands.

Table 2. Industry-wide distributions of p (failure probability) and λ (hourly rate) for EPS EDGs.

Failure Mode	5%	Median	Mean	95%	Distribution		
					Type	α	β
FTS	2.77E-04	3.24E-03	4.53E-03	1.32E-02	Beta	1.075	236.30
FTLR	3.07E-04	2.25E-03	2.90E-03	7.69E-03	Beta	1.411	485.60
FTR>1H	1.52E-04	7.12E-04	8.48E-04	2.01E-03	Gamma	2.010	2371.00

Table 3. Industry-wide distributions of p (failure probability) and λ (hourly rate) for HPCS EDGs.

Failure Mode	5%	Median	Mean	95%	Distribution		
					Type	α	β
FTS	1.16E-4	7.80E-04	9.89E-04	2.58E-3	Beta	1.5	1515.08
FTLR	8.53E-04	2.50E-03	2.75E-03	5.53E-03	Beta	3.5	1268.15
FTR>1H	1.56E-04	5.91E-04	6.80E-04	1.5E-03	Gamma	2.5	3678.81

3.2 EDG Failure Probability and Failure Rate Trends

Trends in the EPS and HPCS failure probabilities and failure rates are shown in Figure 1 to Figure 6. The data for the trend plots are contained in Table 14 to Table 19.

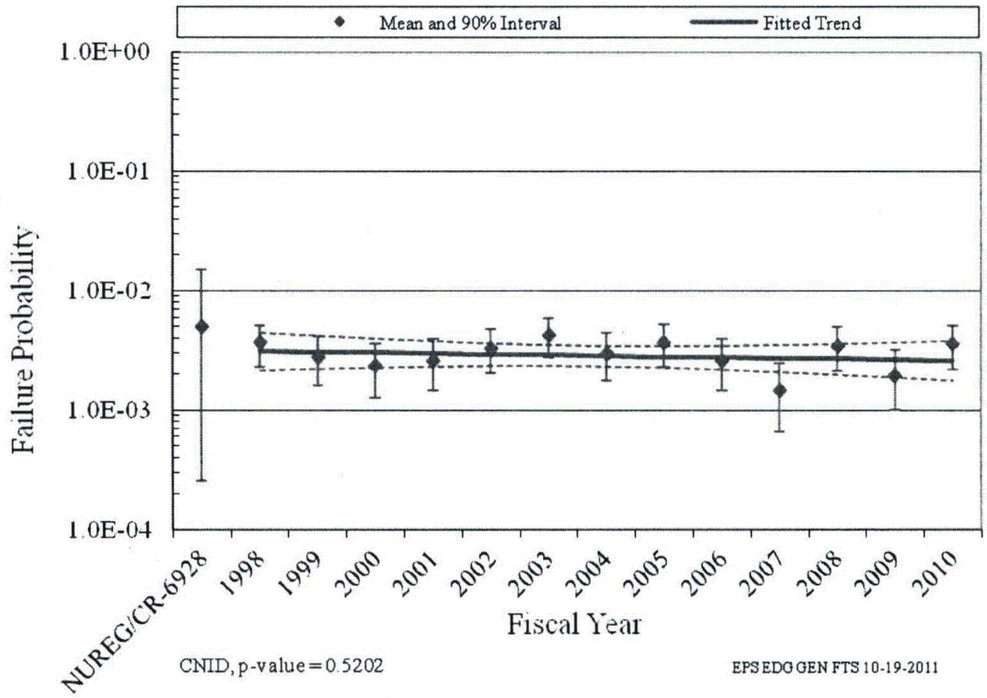

Figure 1. EPS, industry-wide EDG FTS trend.

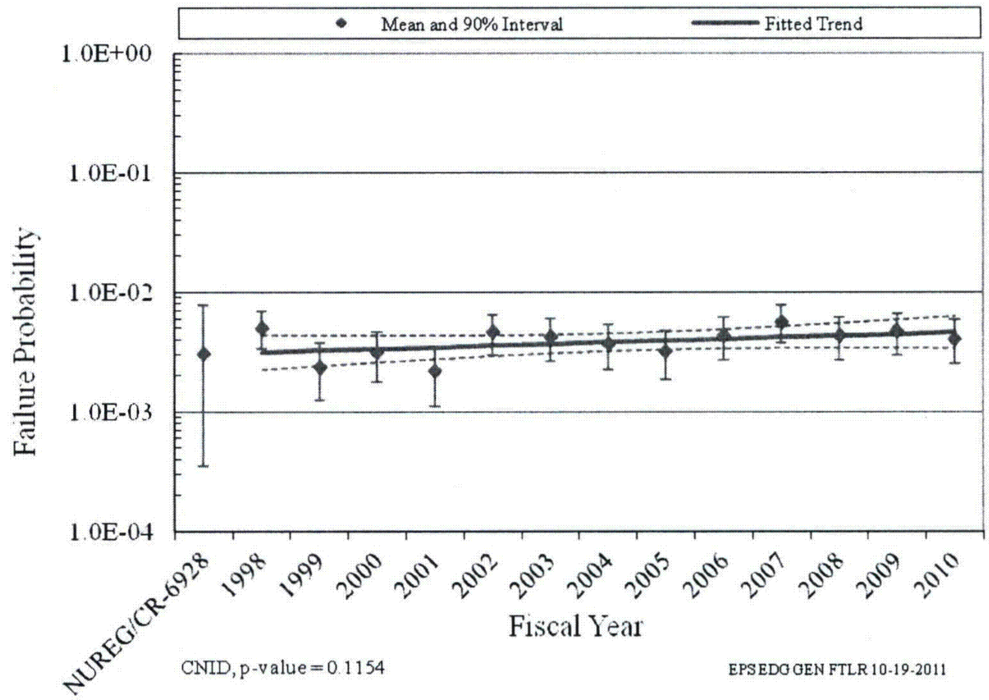

Figure 2. EPS, industry-wide EDG FTLR trend.

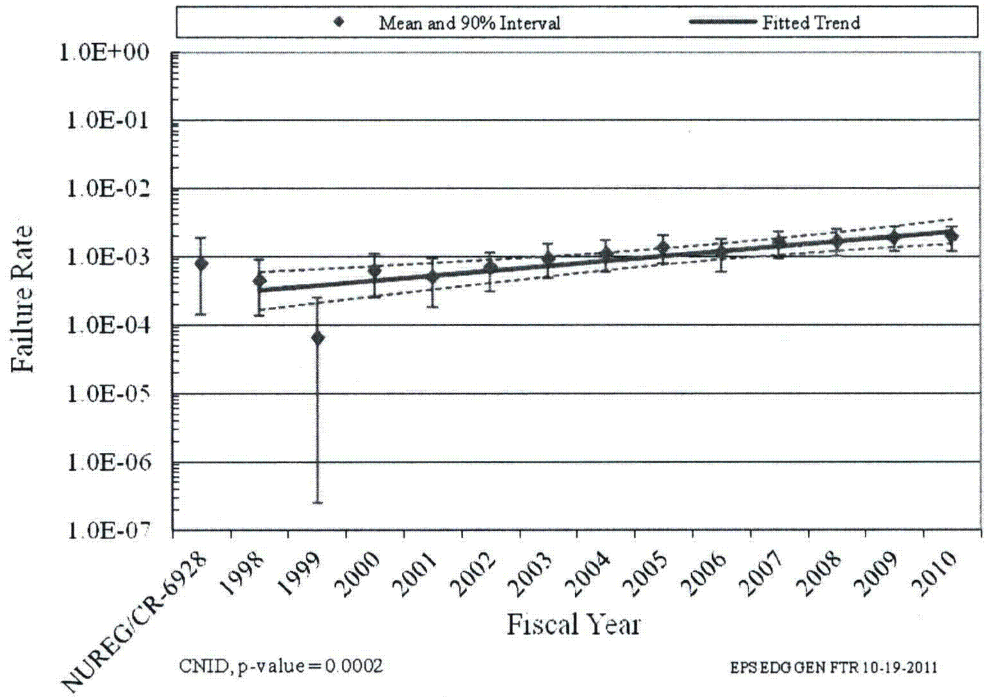

Figure 3. EPS, industry-wide EDG FTR>1H trend.

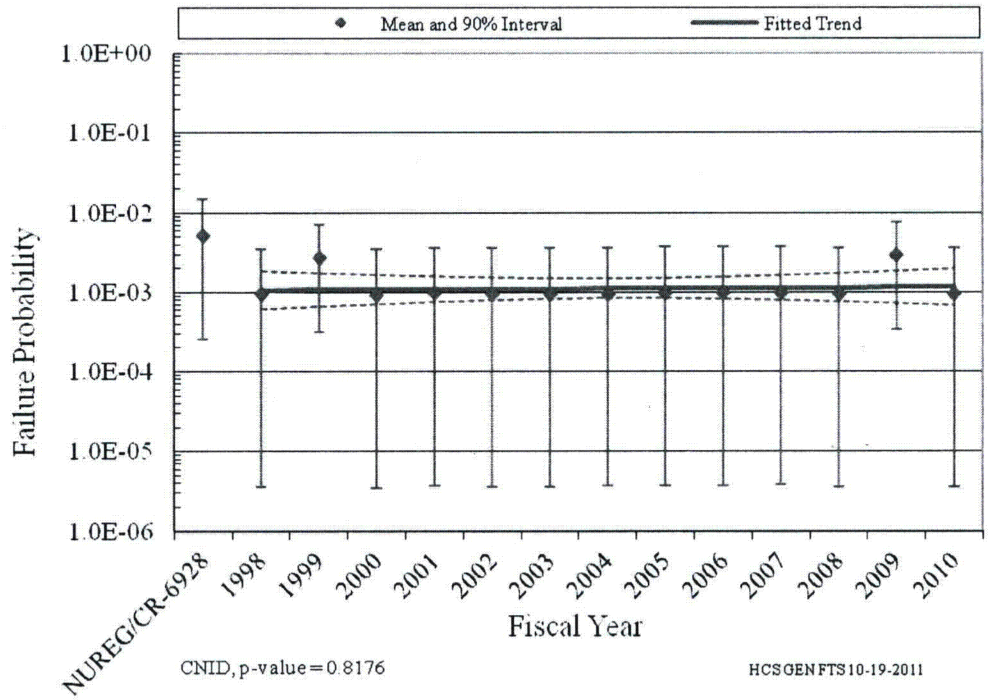

Figure 4. HPCS, industry-wide EDG FTS trend.

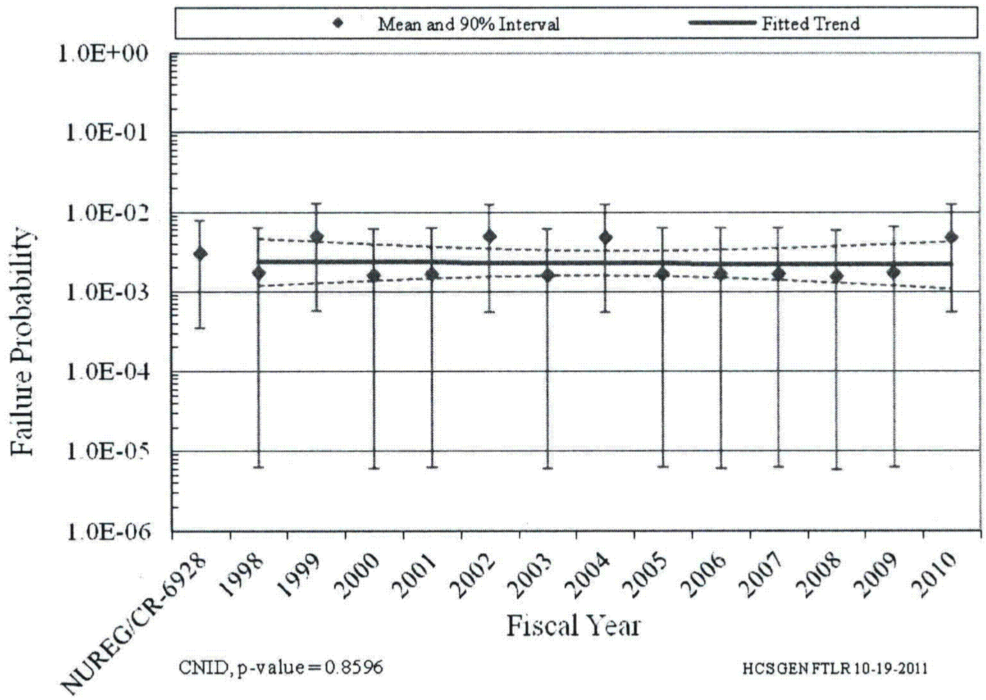

Figure 5. HPCS, industry-wide EDG FTLR trend.

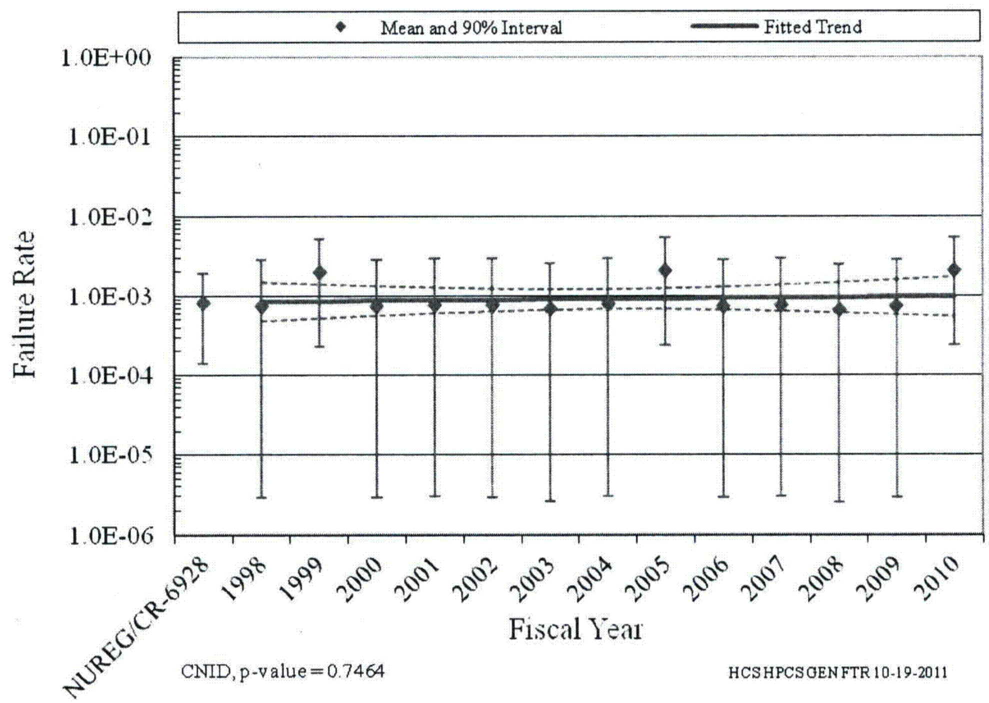

Figure 6. HPCS, industry-wide EDG FTR>1H trend.

In the plots, the means of the posterior distributions from the Bayesian update process were trended across the years. The posterior distributions were also used for the vertical bounds for each year. The 5th and 95th percentiles of these distributions give an indication of the relative variation from year to year in the data. When there are no failures, the interval tends to be larger than the interval for years when there are one or more failures. The larger interval reflects the uncertainty that comes from having little information in that year's data. Such uncertainty intervals are determined by the prior distribution. In each plot, a relatively "flat" constrained noninformative prior distribution (CNID) is used, which has large bounds.

The horizontal curves plotted around the regression lines in the graphs show 90 percent simultaneous confidence bands for the fitted lines. The simultaneous confidence band bounds are larger than ordinary confidence intervals for the trended values because they form a band that has a 90% probability of containing the entire line. In the lower left hand corner of the trend figures, the regression p-values are reported. They come from a statistical test on whether the slope of the regression line might be zero. Low p-values indicate that the slopes are not likely to be zero, and that trends exist.

Further information on the trending methods is provided in Section 2 of the Overview and Reference document. A final feature of the trend graphs is that the baseline industry values from Table 2 are shown for comparison.

4 UNAVAILABILITY

4.1 Overview

The industry-wide test or maintenance unavailability (UA) of EDG trains has been calculated from the operating experience. UA data are for EDG trains, which can include more than just the EDG. However, in most cases the EDG contributes the majority of the UA reported. Table 4 shows overall results for the EDG from Reference 1 based on UA data from MSPI Basis Documents, covering 2002 to 2004. In the calculations, planned and unplanned unavailable hours for a train are combined.

Table 4. Industry distributions of unavailability for EDGs.

Description	Mean	Distribution	α	β
Emergency Diesel Generator Test or Maintenance (EPS)	1.20E-02	Beta	4.00	329.33
Emergency Diesel Generator Test or Maintenance (HPCS)	1.20E-02	Beta	6.00	494.00

4.2 EDG Unavailability Trends

For the 1998-2010 period, the following are overall maintenance unavailability data. Note that these data do not supersede the data in Table 4 for use in risk assessments.

Trends in EDG train unavailability are shown in Figure 7 and Figure 8. Data tables for these figures are Table 20 and Table 21, respectively. The EDGs in systems EPS and HPCS are trended. The trend charts show the results of using data for each year based on selected system-specific component unavailability data over time. The yearly (1998–2010) unavailability and reactor critical hour data were obtained from the ROP (1998 to 2001) and MSPI (2002 to 2010) data for the EDG component. The total downtimes during operation for each plant and year were summed, and divided by the corresponding number of EDG-reactor critical hours. Unavailability data for shutdown periods are not reported.

A change in reporting requirements for UA occurred in 2002. The ROP data (1998–2001) did not include EDG overhaul outages while plants were in critical operation, while the MSPI (2002–2010) requires plants to report such outages. The annual means of these two groups are statistically significant, indicating that there is strong evidence that they differ. This change in reporting is believed to result in most of the approximately 50% increase in UA observed between the 1998–2001 data and the 2002–2010 data. The 1998–2001 data do not exhibit a statistically significant trend as shown in Figure 7. However, the 2002–2010 data do exhibit a statistically significant trend as shown in Figure 7.

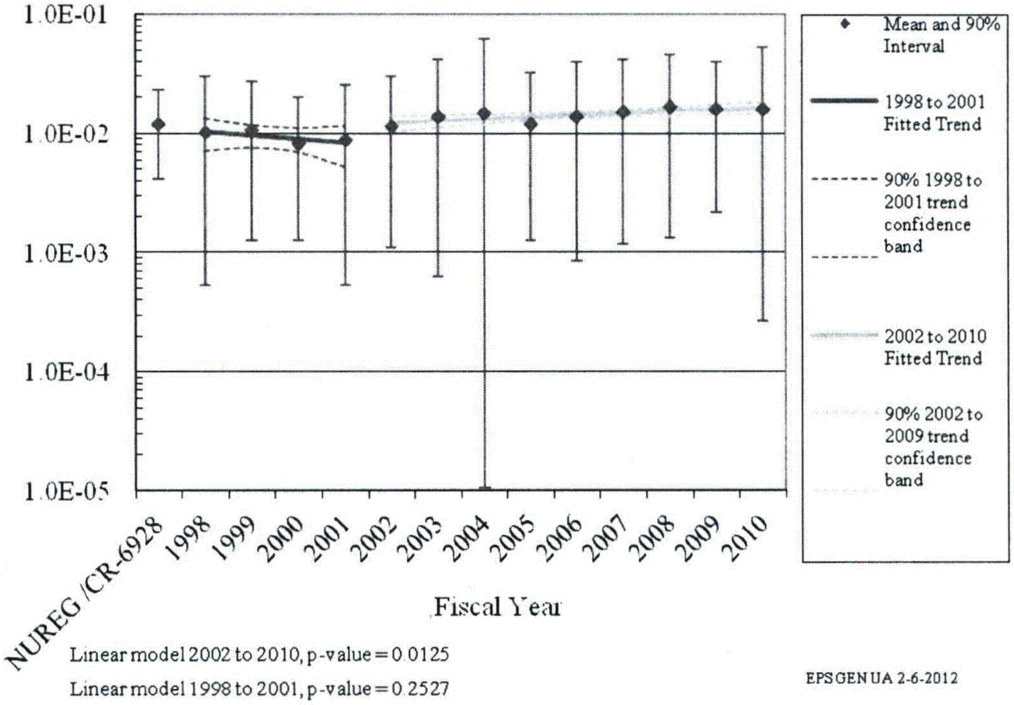

Figure 7. EPS EDG UA trend.

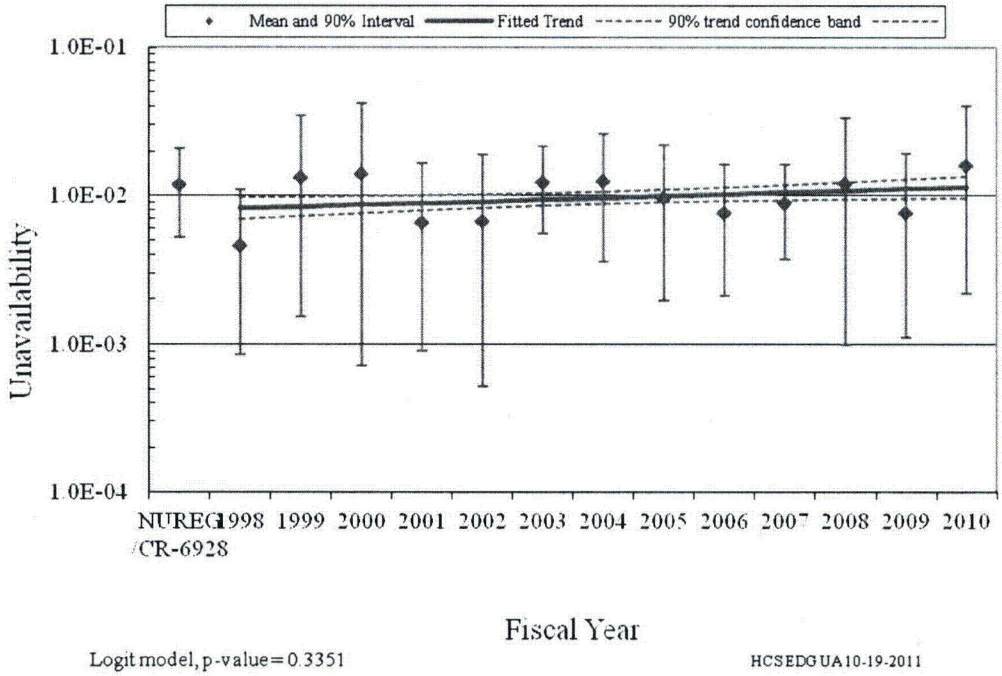

Figure 8. HPCS EDG UA trend.

The mean and variance for each year is the sample mean and variance calculated from the plant-level unavailabilities for that year. The vertical bar spans the calculated 5th to 95th percentiles of the beta distribution with matching means.

Further information on the trending methods is provided in Section 3 of the Overview and Reference document. In the lower left hand corner of the trend figures, the p-value is reported.

5 EDG UNRELIABILITY TRENDS

Trends in total component unreliability are shown in Figure 9 and Figure 10. Plot data for these Figures are in Table 22 and Table 23, respectively. Total unreliability is defined as the result of an OR gate with the FTS, FTLR, FTR, and UA as basic event inputs. The probability of FTR is calculated for 7 hours to provide the results for an 8-hour mission. The trends are shown at the system-specific level across the industry. The trending method is described in more detail in Section 4 of the Overview and Reference document. In the lower left hand corner of the trend figures, the regression method is reported.

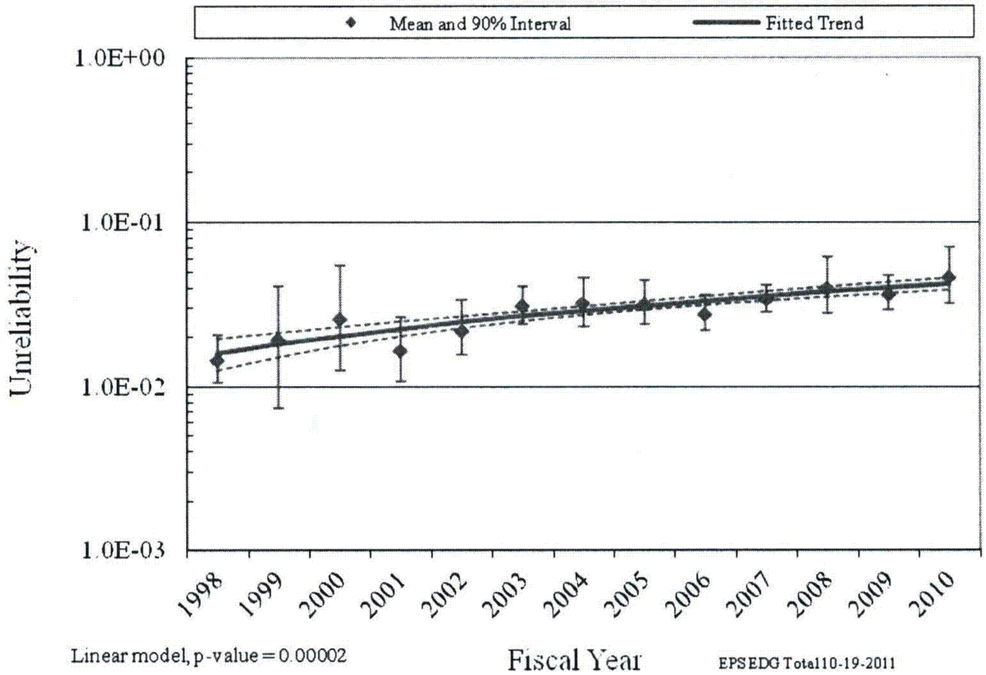

Figure 9. EPS, industry-wide EDG unreliability trend (8-hour mission).

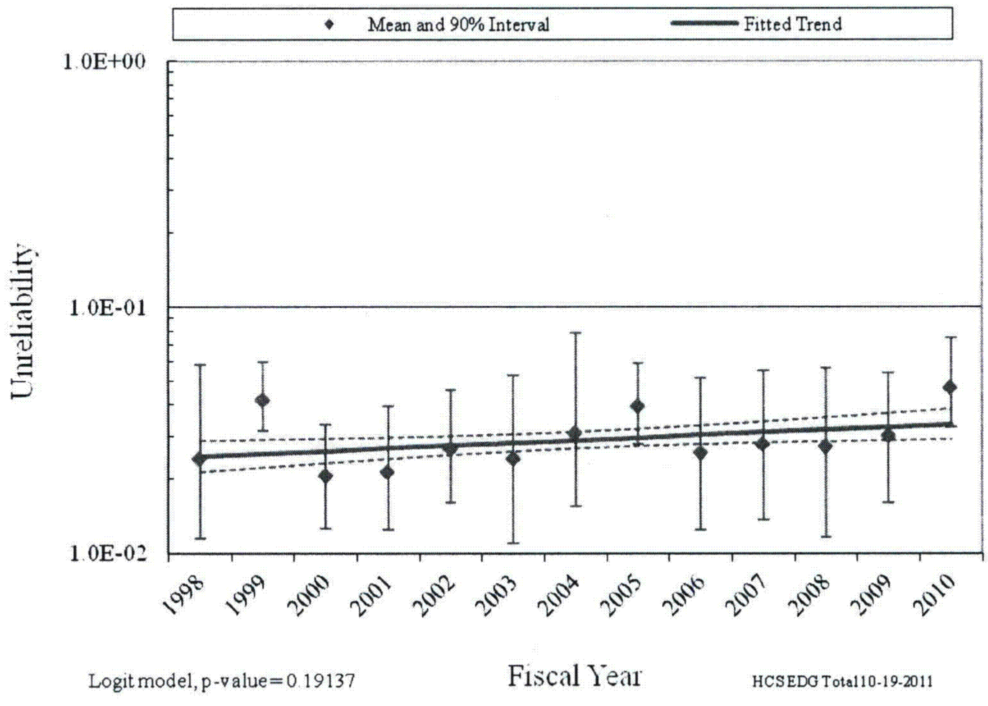

Figure 10. HPCS, industry-wide EDG unreliability trend (8-hour mission).

6 ENGINEERING ANALYSIS

The engineering analysis section presents an analysis of factors that could influence the system and component trends. Engineering trends of component failures and demands are presented in Section 6.1. Differences between testing and actual unplanned demands are presented in Section 6.2, differences among manufacturers are presented in Section 6.3, and differences among EDG ratings are presented in Section 6.4. Statistical analyses of these differences are performed and results showing whether pooling is acceptable across these factors. In addition, engineering analyses were performed with respect to time period and failure mode are presented in Section 6.5. The factors analyzed were: sub-component, failure cause, detection method, manufacturer, and EDG rating.

6.1 Engineering Trends

This section presents frequency trends for EPS and HPCS EDG failures and demands. The data are normalized by reactor year for plants that have the equipment being trended. Figure 11 shows the trend for EPS and HPCS EDG demands. Figure 12 shows the trend for EPS and HPCS EDG load and run demands. Figure 13 shows the trend for the EPS and HPCS EDG run hours. Table 24, Table 25, and Table 26 provide the plot data, respectively.

Figure 14 shows the trend for EPS and HPCS EDG FTS events. Figure 15 shows the trend EPS and HPCS EDG FTLR events and Figure 16 shows the trend for the EPS and HPCS EDG FTR events. Table 27, Table 28, and Table 29 provide the plot data, respectively.

Table 5 summarizes the failures by system and year for the FTS failure mode. Table 6 summarizes the failures by system and year for the FTLR failure mode. Table 7 summarizes the failures by system and year for the FTR>1H failure mode.

The systems from Table 1 are trended together for each figure. The rate methods described in Section 2 of the Overview and Reference document are used.

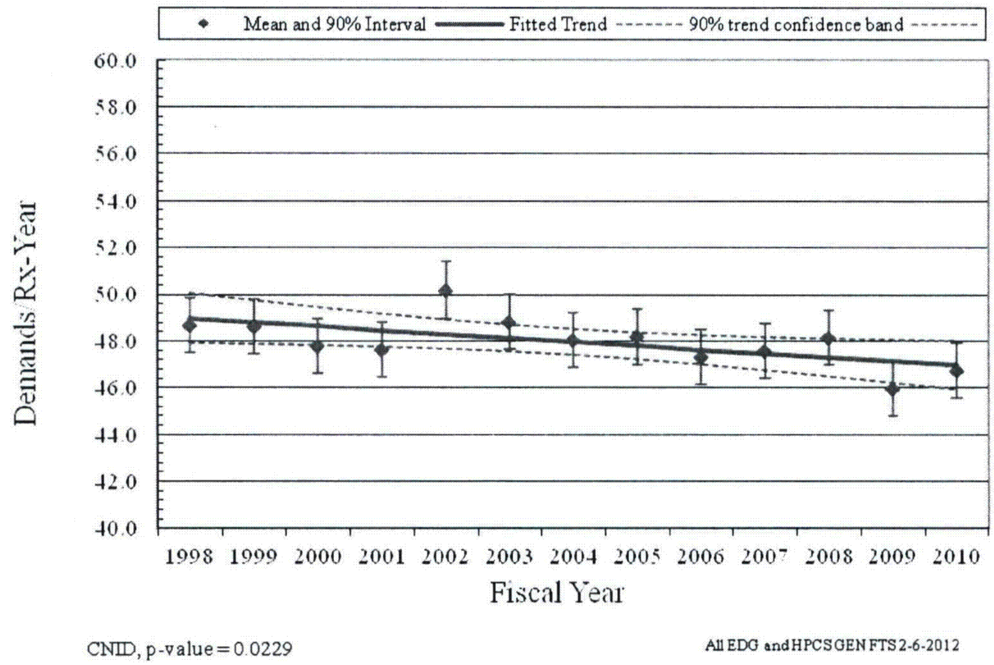

Figure 11. Frequency (events per reactor year) of start demands, EPS and HPCS EDGs.

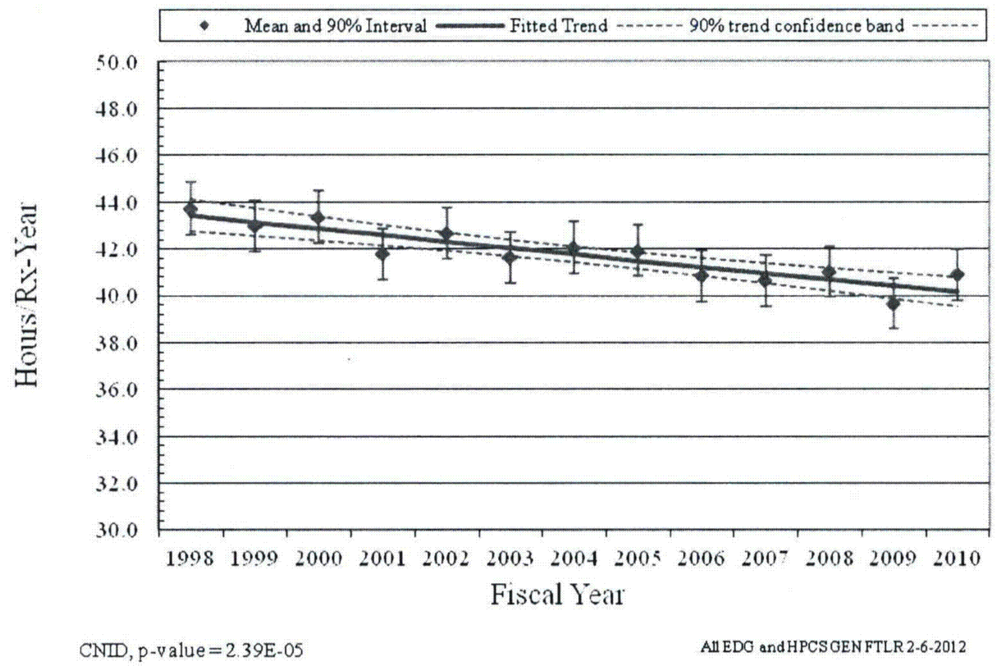

Figure 12. Frequency (events per reactor year) of load and run ≤ 1 hour demands, EPS and HPCS EDGs.

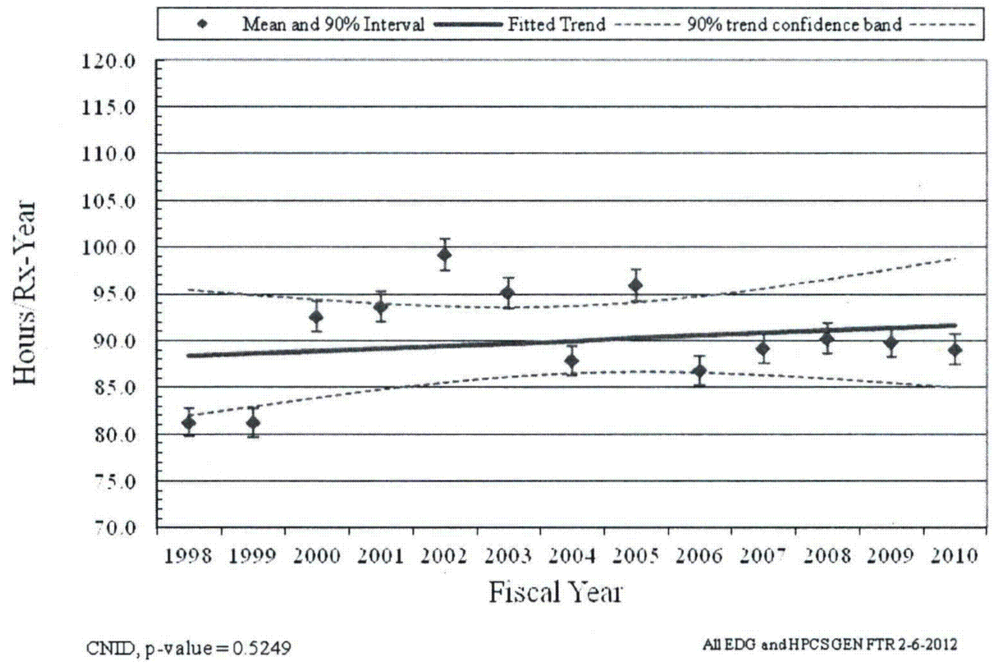

Figure 13. EPS and HPCS EDG run hours per reactor year.

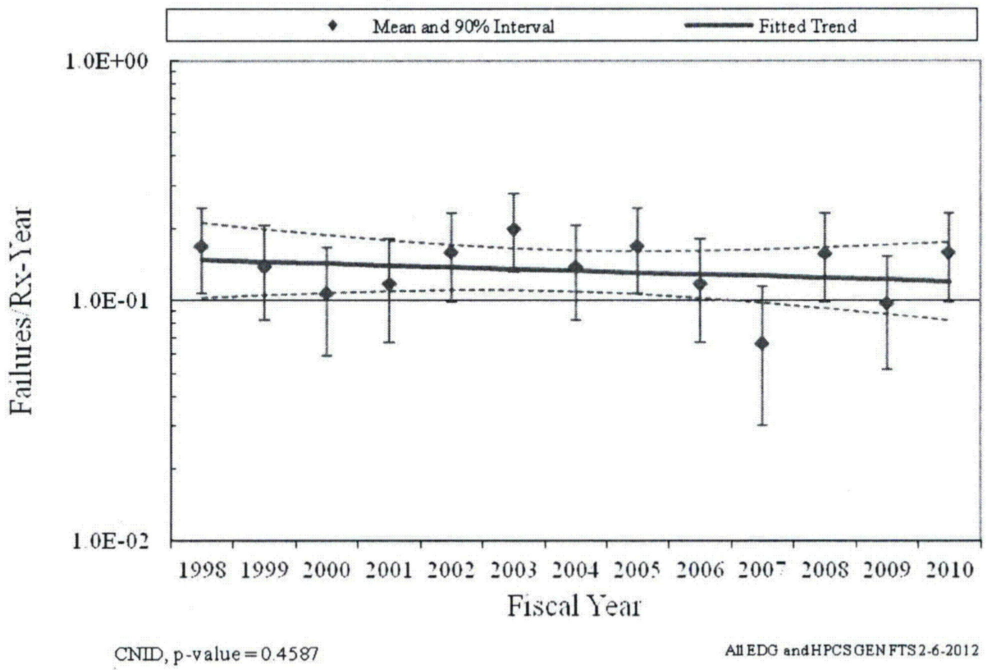

Figure 14. Frequency (events per reactor year) of FTS events, EPS and HPCS EDGs.

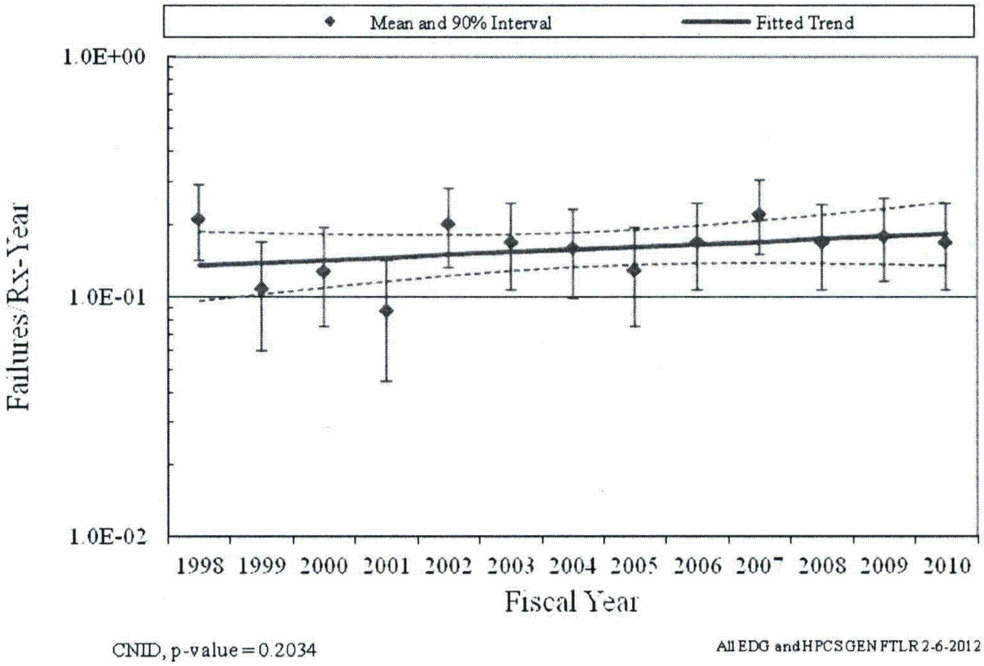

Figure 15. Frequency (events per reactor year) of FTLR events, EPS and HPCS EDGs.

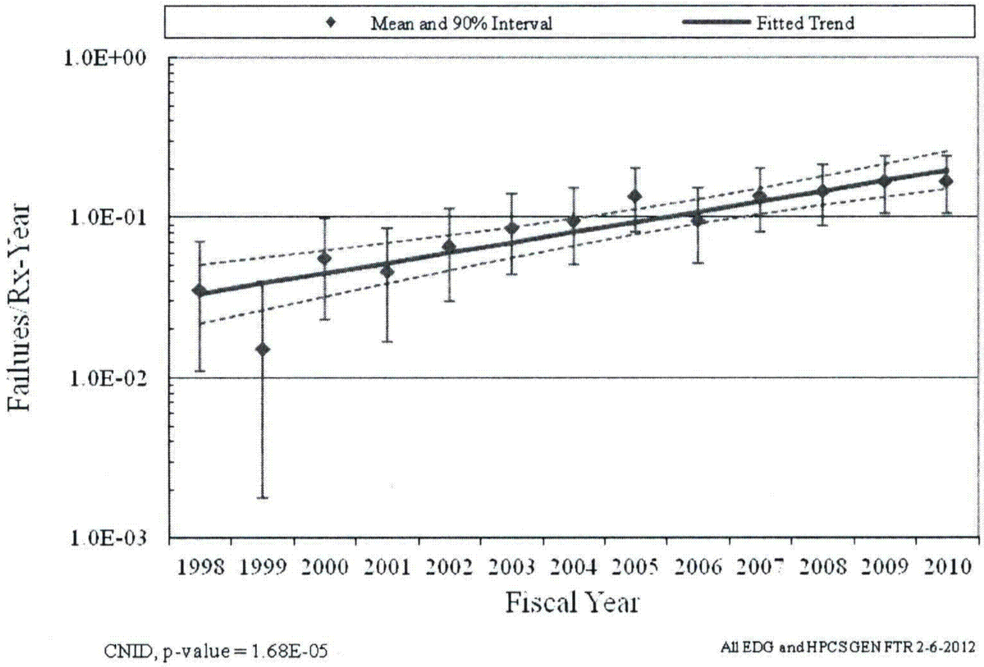

Figure 16. Frequency (events per reactor year) of FTR>1H events, EPS and HPCS EDGs.

Table 5. Summary of EDG failure counts for the FTS failure mode over time by system.

System Code	*EDG Count*	*EDG Percent*	*FY 98*	*FY 99*	*FY 00*	*FY 01*	*FY 02*	*FY 03*	*FY 04*	*FY 05*	*FY 06*	*FY 07*	*FY 08*	*FY 09*	*FY 10*	*Total*	*Percent of Failures*
EPS	223	96.5%	16	12	10	11	15	19	13	16	11	6	15	8	15	167	98.8%
HCS	8	3.5%		1										1		2	1.2%
Total	231	100.0%	16	13	10	11	15	19	13	16	11	6	15	9	15	169	100.0%

Table 6. Summary of EDG failure counts for the FTLR failure mode over time by system.

System Code	*EDG Count*	*EDG Percent*	*FY 98*	*FY 99*	*FY 00*	*FY 01*	*FY 02*	*FY 03*	*FY 04*	*FY 05*	*FY 06*	*FY 07*	*FY 08*	*FY 09*	*FY 10*	*Total*	*Percent of Failures*
EPS	223	96.5%	20	9	12	8	18	16	14	12	16	22	16	17	16	196	98.0%
HCS	8	3.5%		1			1		1						1	4	2.0%
Total	231	100.0%	20	10	12	8	19	16	15	12	16	22	16	17	17	200	100.0%

Table 7. Summary of EDG failure counts for the FTR>1H failure mode over time by system.

System Code	*EDG Count*	*EDG Percent*	*FY 98*	*FY 99*	*FY 00*	*FY 01*	*FY 02*	*FY 03*	*FY 04*	*FY 05*	*FY 06*	*FY 07*	*FY 08*	*FY 09*	*FY 10*	*Total*	*Percent of Failures*
EPS	223	96.5%	3		5	4	6	8	9	12	9	13	14	16	16	115	97.5%
HCS	8	3.5%		1						1					1	3	2.5%
Total	231	100.0%	3	1	5	4	6	8	9	13	9	13	14	16	17	118	100.0%

6.2 Comparison of EPIX EPS EDG Unplanned Demand Results with Industry Results

Because the EPIX EPS EDG data are dominated by test demands (over 95% of the demands are typically from tests), an ongoing concern is whether these mostly test data adequately represent EPS EDG performance during unplanned demands. This comparison evaluates the same dataset for standby components that is used for the overall trends shown in this document, but limits the failure data to those that are discovered during an ESF demand and the ESF demands reported in EPIX. The data are further limited to FY 2003 to present since the ESF demand reporting in EPIX is inconsistent prior to FY 2003.

To answer this question, EPIX failure records were reviewed to identify actual unplanned EPS EDG demands involving bus under voltage conditions. Such events require the associated EPS EDG to start, load onto the bus and power the bus until normal power is recovered to the bus. There are additional EPS EDG unplanned demands in which a bus under voltage condition did not exist. In those cases, the EPS EDG did not have to load and power the bus. Such unplanned demands do not fully exercise the mission of the EPS EDGs and therefore were not counted.

The EPS EDG unplanned demand data covering FY 2003 – 2010 are summarized in Table 8. Consistency between the unplanned demand data and industry-average performance (from Table 2) was evaluated using the predictive distribution approach outlined in the *Handbook of Parameter Estimation for Probabilistic Risk Assessment*, NUREG/CR-6823, Sections 6.2.3.5 and 6.3.3.4 [Reference 2]. Simulation is required.

The unplanned demand data were aggregated at the plant level (failures and demands). Assuming each plant can have a different failure probability, the industry-average distribution (from Table 2) was sampled for each plant. The predicted number of events for each plant was evaluated using the binomial distribution with the plant-specific failure probability and its associated number of demands. Then the total number of predicted failures was obtained by summing the individual plant results. This process was repeated 1000 times (Latin hypercube sampling), each time obtaining a total number of predicted failures. The 1000 sample results were ordered from high to low. Then the actual number of unplanned demand failures observed (listed in Table 8) was compared with this ordered sample to determine the probability of observing this number of failures or greater. If the probability was greater than 0.05 and less than 0.95, then the unplanned demand performance was considered to be consistent with the industry-average distribution obtained from the EPIX data analysis.

Table 8. EPS EDG unplanned demand performance comparison with industry-average performance from EPIX data.

Failure Modes	Plants	Demands or Hours	Failures	Expected Failures	Probability of ≥ Failures	Consistent with Industry-Average Performance?
FTS	96	253	0	1.1	1.00	No
FTLR	96	160	1	0.5	0.35	Yes
FTR	96	1427.0	4	9.7	0.08	Yes
Total EDG Unreliability (8 hours)	96	253 and 1,427.0 h	5	11.3	0.21	Yes

The consistency checks using unplanned demand data indicate that the FTLR and FTR failure observations and the Total EDG unreliability are consistent with their industry-average distribution from Table 2. The EPS EDG FTS lies in the upper 95% of the predictive distribution (superior performance).

6.3 EPS EDG Performance by Manufacturer

Table 9 presents the results of the evaluation of EPS EDG performance by manufacturer. EPIX contains information on EPS EDG manufacturers, but it appears that over the years some manufacturers have changed names or have been acquired by other manufacturers. Therefore, in order to identify the original manufacturer, the EPIX information was supplemented by other EPS EDG reports. The results are a consistency check against the industry-average distributions in Table 2. The comparison was made for the combination of all three failure modes. One manufacturer's EPS EDG performance lies in the lower 5% (degraded performance), however, this manufacturer involves very few EPS EDGs, and so the data are limited. The rest of the manufacturers lie within the 5% to 95% interval and are consistent with the industry-average performance.

Table 9. EPS EDG performance by manufacturer.

EPS EDG Manufacturer Performance Consistency with Industry-Average Performance - FTS, FTLR, and FTR Combined						
Manufacturer	Code	EPS EDGs	Observed Failures	Expected Failures	Probability ≥ Observed Failures	Consistent with Industry-Average Performance? (note a)
Worthington Corp	WC	4	17	6.7	0.03	No
SAC/Compair Luchard/Jeumont Schndr	SC/JS	3	11	5.0	0.07	Yes
Fairbanks Morse/Colt	FM/C	65	161	128.1	0.10	Yes
TransAmerica DeLaval	TD	20	54	41.9	0.19	Yes
Nordberg	NB	8	22	18.9	0.37	Yes
Electro Motive/General Motors	EM/GM	68	135	144.7	0.51	Yes
ALCO Power	AP	24	40	48.2	0.79	Yes
Cooper Bessemer	CB	31	60	73.0	0.91	Yes
Totals		223	500	466.6		

a. If the probability of observing the actual failures or greater is ≥ 0.05 and ≤ 0.95, then the manufacturer performance is considered to be consistent with the industry-average performance.

6.4 EPS EDG Performance by Rating

Table 10 presents the results of the evaluation of EPS EDG performance by rating. The results are a consistency check against the industry-average distributions in Table 2. The comparison was made for the combination of all three failure modes. The ratings all lie within the 5% to 95% interval and are consistent with the industry-average performance.

Table 10. EPS EDG performance by rating.

EPS EDG Rating Performance Consistency with Industry-Average Performance – FTS, FTLR, and FTR Combined					
Rating	EPS EDGs	Observed Failures	Expected Failures	Probability ≥ Observed Failures	Consistent with Industry-Average Performance? (note a)
50-249 KW	2	2	5.1	0.90	Yes
1,000-4,999 KW	169	374	347.6	0.21	Yes
5,000-99,999 KW	52	129	113.9	0.31	Yes
Totals	223	505	466.6		
a. If the probability of observing the actual failures or greater is ≥ 0.05 and ≤ 0.95, then the rating performance is considered to be consistent with the industry-average performance.					

6.5 EPS EDG Engineering Analysis by Failure Modes

The engineering analysis of EPS EDG failure sub-components, causes, detection methods, and recovery are presented in this section. Each analysis divides the events into two periods: before July 2003 and after July 2003 (the start of the data begins in FY 1998 and the last date is FY 2010). This breakdown was chosen for two reasons: first, July 2003 represents a point in which the MSPI data collection attains a "higher level" of scrutiny; second, this date represents a point about half way through the full data period.

The second division of the events is by the failure mode determined after EPIX data review by the staff. See Section 7 for more description of failure modes.

EPS EDG sub-component contributions to the three failure modes are presented in Figure 17. The sub-component contributions are similar to those used in the CCF database. For FTS, instrumentation and control and the generator piece parts have the highest percentage contributions to failures. FTLR high contributors include the breaker and instrumentation and control. Finally, FTR high contributors include the cooling, engine, fuel oil, and instrumentation and control.

EPS EDG cause group contributions to the three failure modes are presented in Figure 18. The cause groups are similar to those used in the CCF database. Table 11 shows the breakdown of the cause groups with the specific causes that were coded during the data collection. The most likely cause is grouped as Internal. Internal means that the cause was related to something within the EPS EDG component such as a worn out part or the normal internal environment. Of particular interest is the Design cause group under the fail to run failure mode. Notice that this group increased in importance in the current period over the previous period.

EPS EDG detection methods to the three failure modes are presented in Figure 19. The most likely detection method is testing, which is the prevalent detection method for most standby components.

EPS EDG recovery to the three failure modes are presented in Figure 20. The overall non-recovery to recovery ratio is approximately 10:1.

Table 11. Component failure cause groups.

Group	Specific Cause	Description
Design	Construction/installation error or inadequacy	Used when a construction or installation error is made during the original or modification installation. This includes specification of incorrect component or material.
Design	Design error or inadequacy	Used when a design error is made.
Design	Manufacturing error or inadequacy	Used when a manufacturing error is made during component manufacture.
External	State of other component	Used when the cause of a failure is the result of a component state that is not associated with the component that failed. An example would be the diesel failed due to no fuel in the fuel storage tanks.
External	Ambient environmental stress	Used when the cause of a failure is the result of an environmental condition from the location of the component.
Human	Accidental action (unintentional or undesired human errors)	Used when a human error (during the performance of an activity) results in an unintentional or undesired action.
Human	Human action procedure	Used when the procedure is not followed or the procedure is incorrect. For example: when a missed step or incorrect step in a surveillance procedure results in a component failure.
Human	Inadequate maintenance	Used when a human error (during the performance of maintenance) results in an unintentional or undesired action.
Internal	Internal to component, piece-part	Used when the cause of a failure is a non-specific result of a failure internal to the component that failed other than aging or wear.
Internal	Internal environment	The internal environment led to the failure. Debris/Foreign material as well as an operating medium chemistry issue.
Internal	Setpoint drift	Used when the cause of a failure is the result of setpoint drift or adjustment.
Internal	Age/Wear	Used when the cause of the failure is a non-specific aging or wear issue.
Other	Unknown	Used when the cause of the failure is not known.
Other	Other (stated cause does not fit other categories)	Used when the cause of a failure is provided but it does not meet any one of the descriptions.
Procedure	Inadequate procedure	Used when the cause of a failure is the result of an inadequate procedure operating or maintenance.

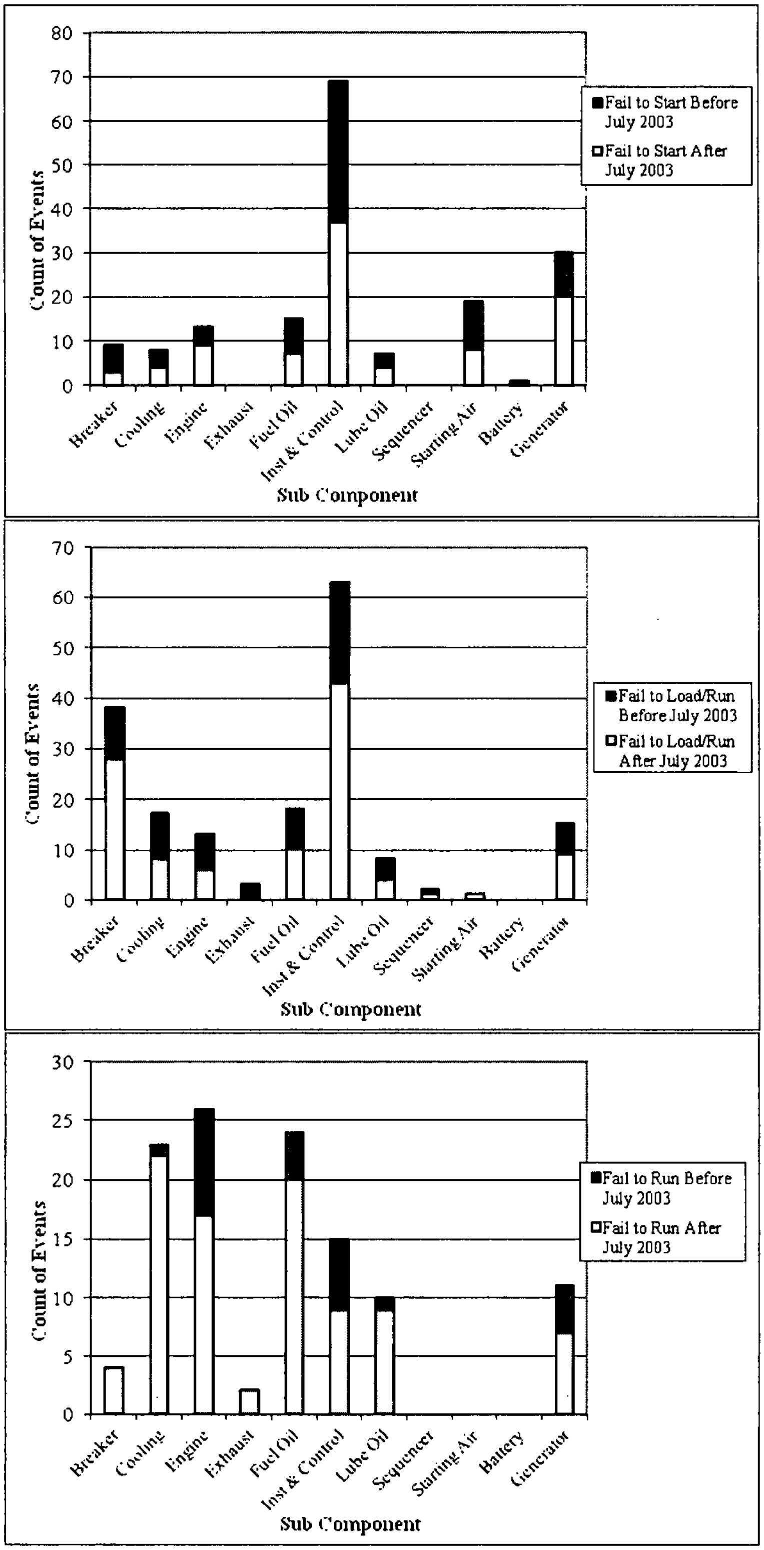

Figure 17. EPS EDG failure breakdown by period, sub component, and failure mode.

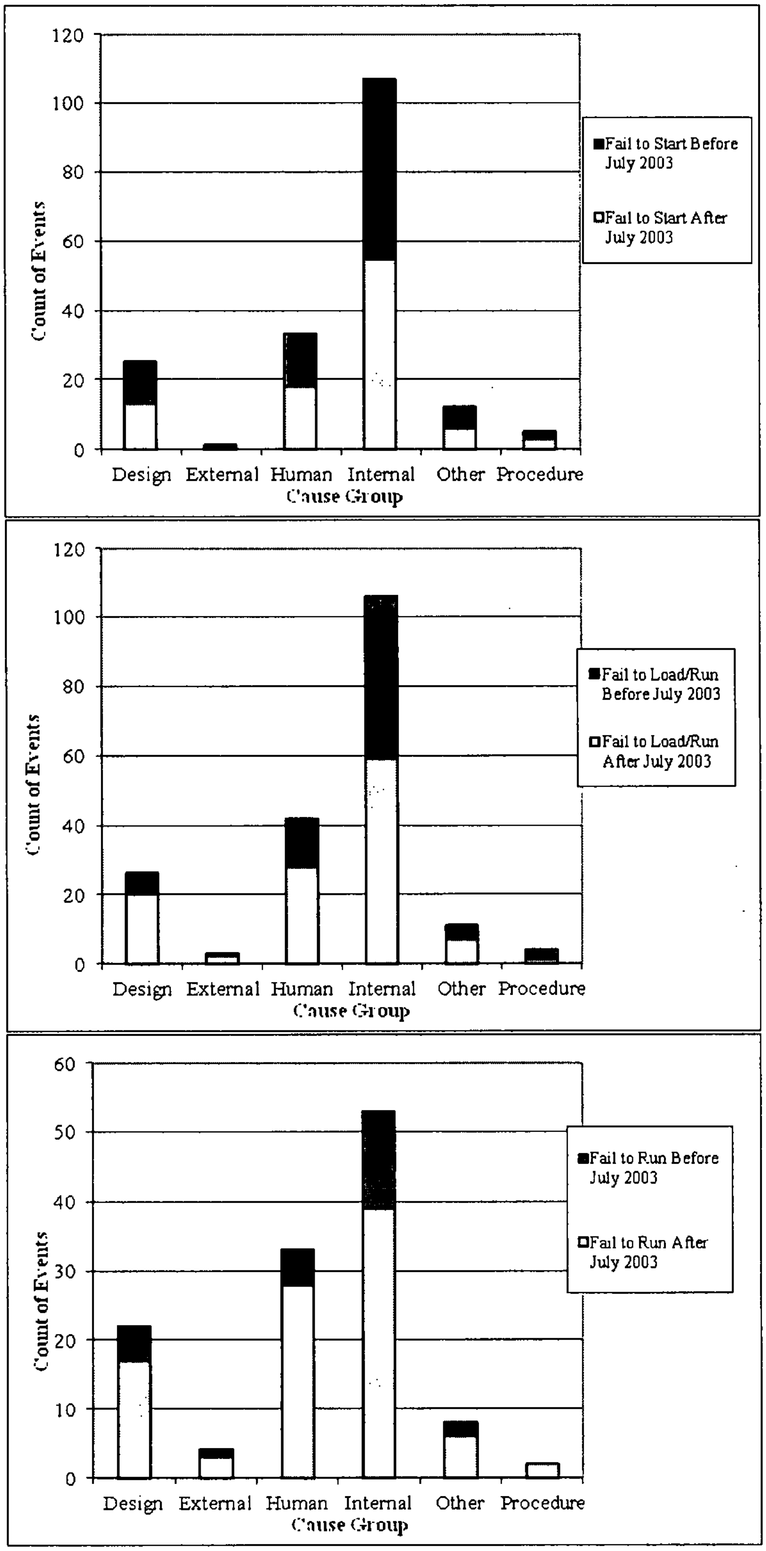

Figure 18. EPS EDG breakdown by time period, cause group, and failure mode.

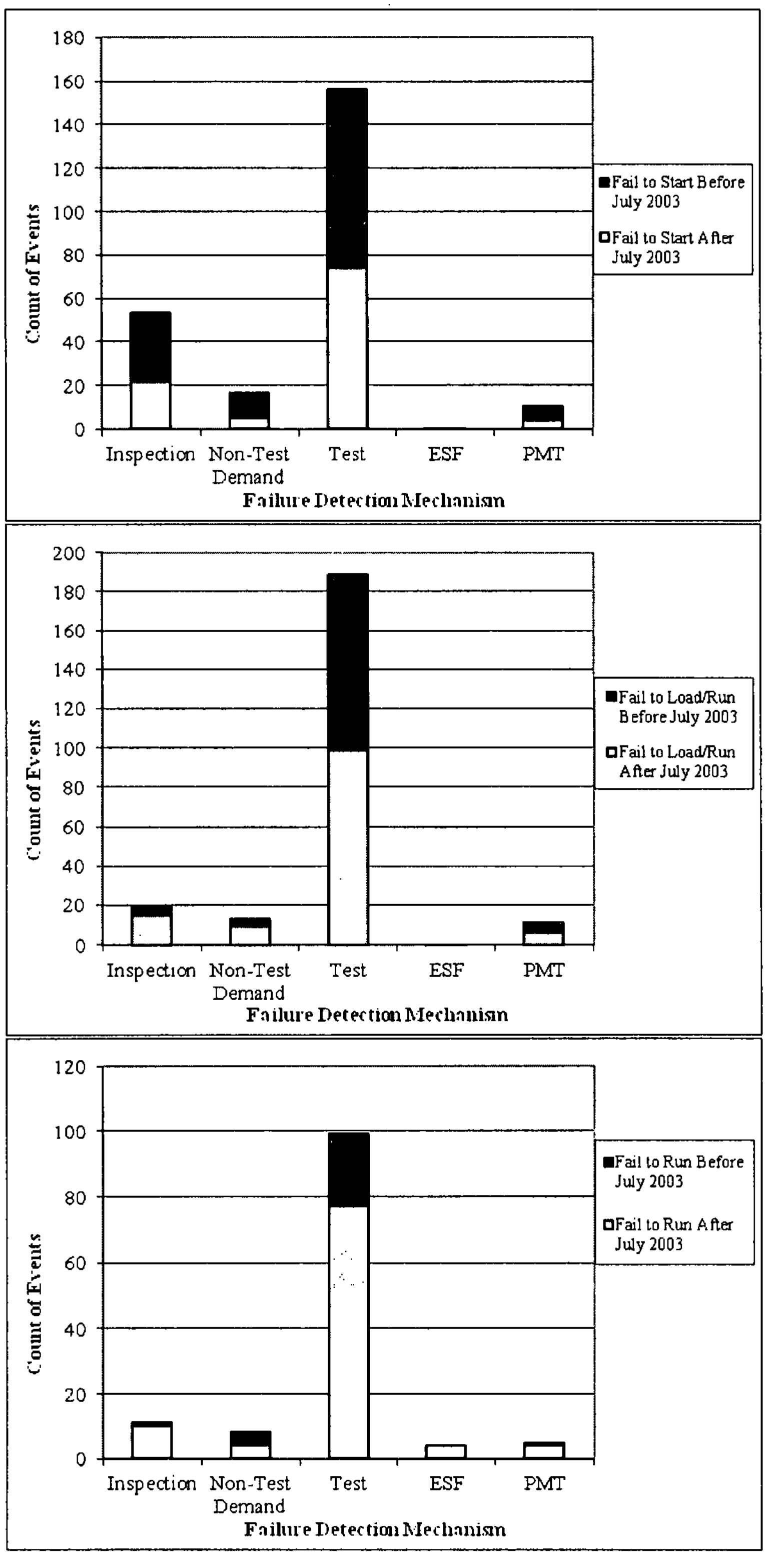

Figure 19. EPS EDG component failure distribution by period, failure mode, and method of detection.

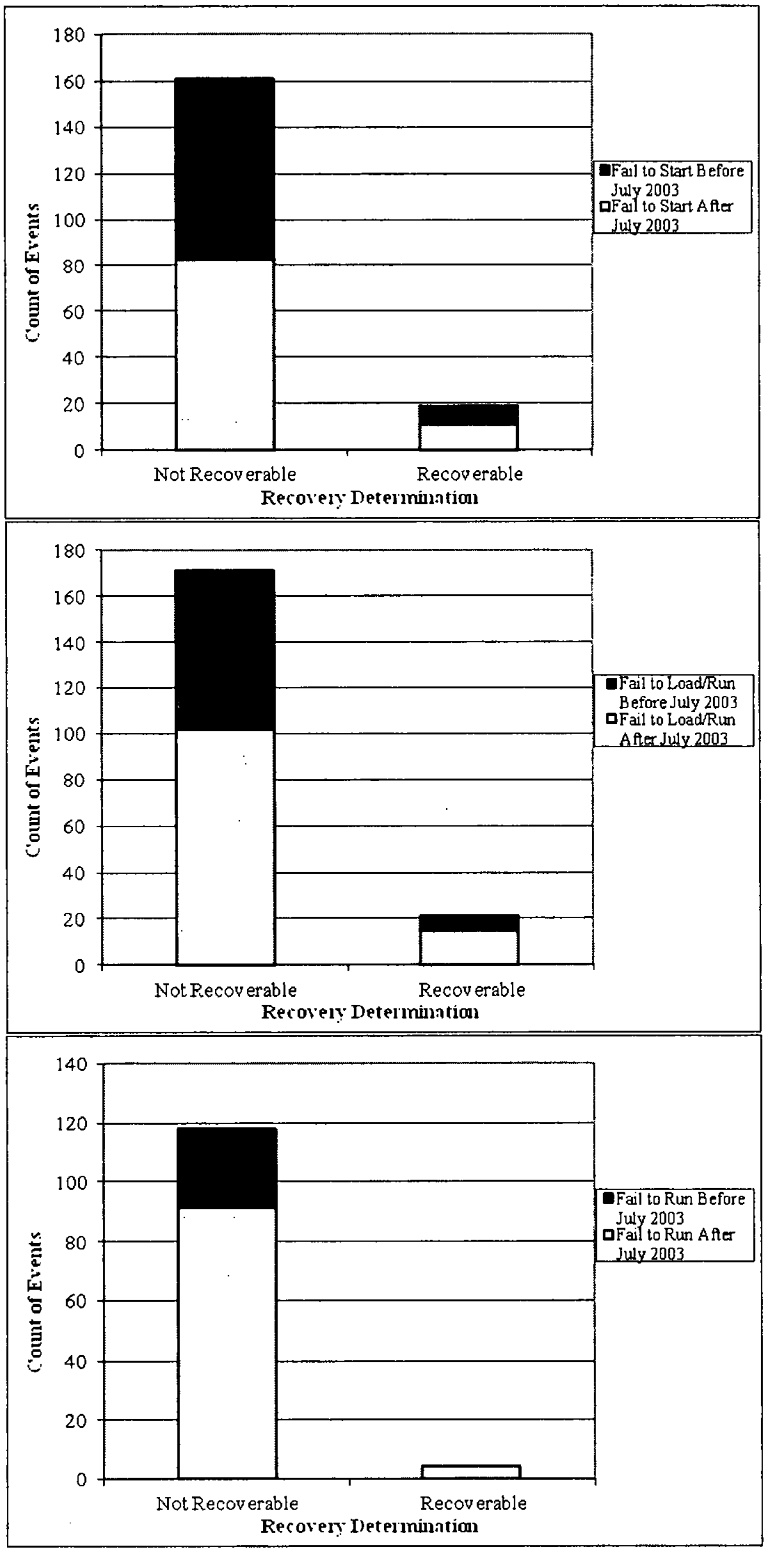

Figure 20. EPS EDG component failure distribution by period, failure mode, and recovery.

Figure 21 shows the percentage of failure events for the three failure modes segregated by EPS EDG manufacturer as indicated in the EPIX database. Table 12 shows the distribution of the various manufacturers of EPS EDGs in the EPIX database used in this study. Based on the information given in Figure 21, the EPS EDG manufacturer is not correlated to any particular failure mode distribution. The EPS EDG manufacturer group SAC/Compair Luchard/Jeumont Schndr does not show any fail to start events, but also only has three EDGs in that group.

Table 12. EPS EDG population manufacturers.

Manufacturer	Code	EPS EDGs
Worthington Corp	WC	4
Nordberg	NB	8
SAC/Compair Luchard/Jeumont Schndr	SC/JS	3
TransAmerica DeLaval	TD	20
ALCO Power	AP	24
Fairbanks Morse/Colt	FM/C	65
Cooper Bessemer	CB	31
Electro Motive/General Motors	EM/GM	68
Totals		223

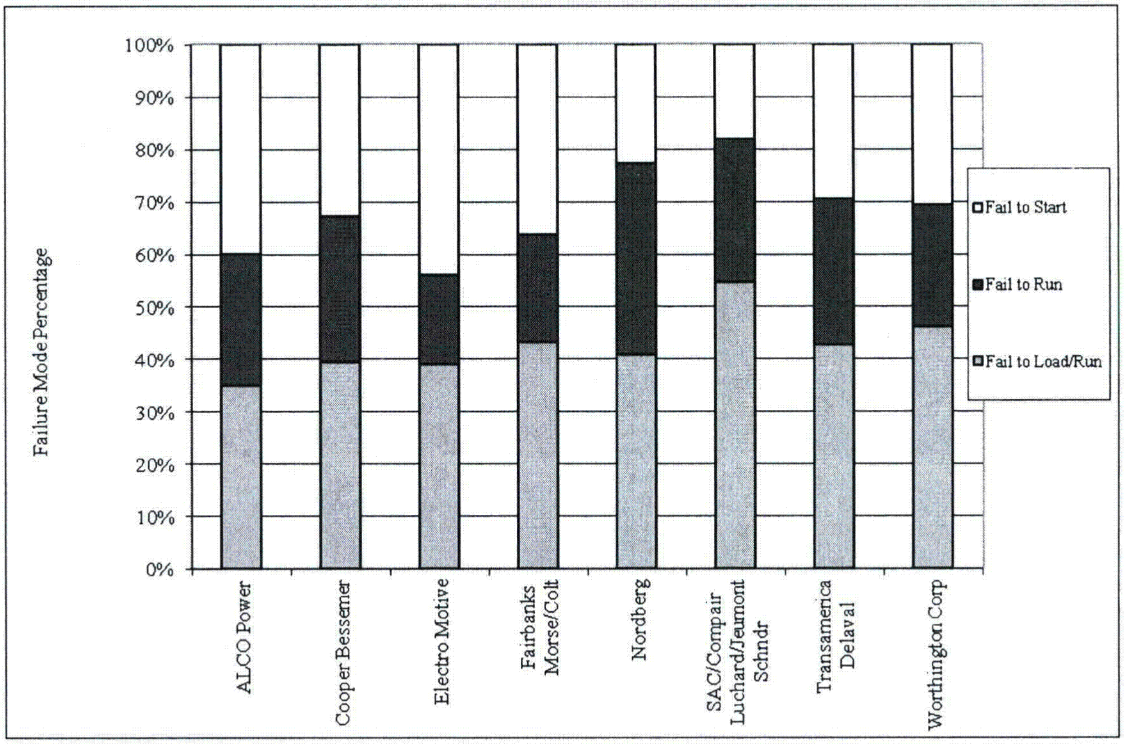

Figure 21. EPS EDG failure distribution by manufacturer.

Figure 22 shows the percentage of failure events for the three failure modes segregated by EPS EDG rating as indicated in the EPIX database. Table 13 shows the distribution of the various rated EPS

EDGs in the EPIX database used in this study. Based the information given in Figure 22, the EPS EDG rating is not correlated to any particular failure mode distribution.

Table 13. EPS EDG population by rating.

EPS EDG Rating	Count
50-249 KW	2
1,000-4,999 KW	169
5,000-99,999 KW	52
Total	223

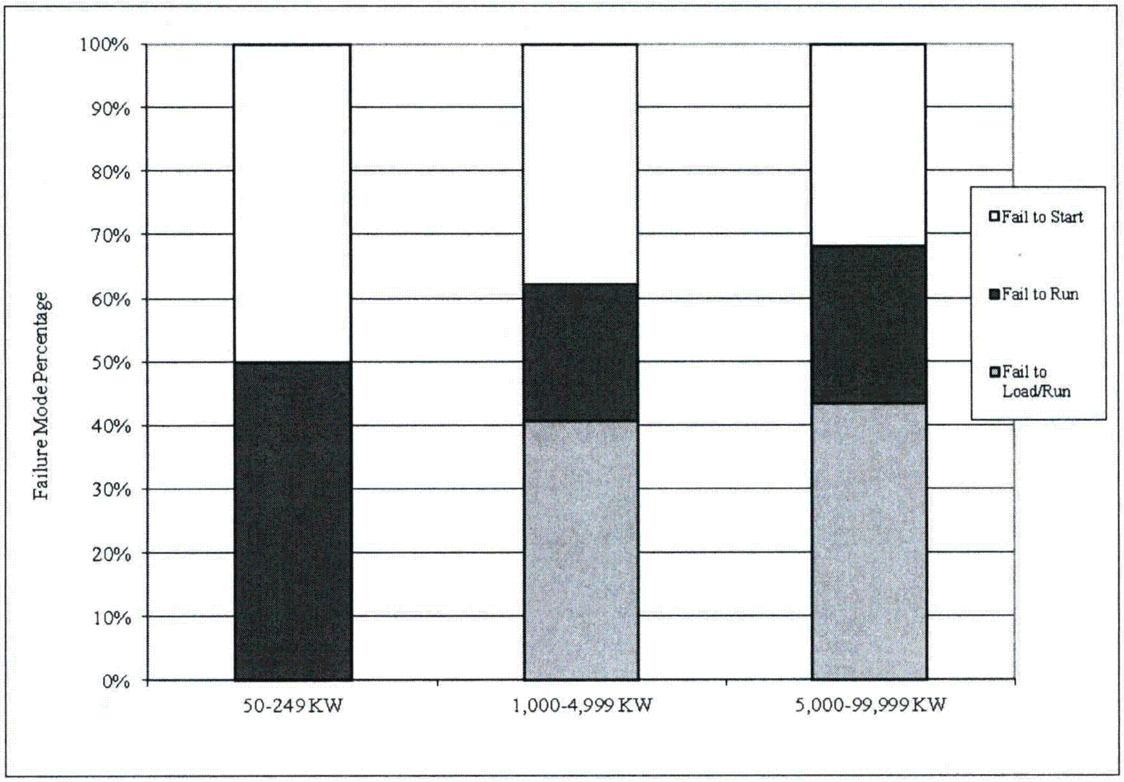

Figure 22. EPS EDG component failure modes by EPS EDG rating.

7 EPS EDG ASSEMBLY DESCRIPTION

The emergency diesel generators (EDGs) are those within the Class 1E ac electrical power system at U.S. commercial nuclear power plants and those in the high-pressure core spray (HPCS) systems. Station blackout (SBO) EDGs are not included.

The EDG includes the diesel engine with all components in the exhaust path, electrical generator, generator exciter, output breaker, combustion air, lube oil systems, fuel oil system, and starting compressed air system, and local instrumentation and control circuitry. The sequencer is excluded from the EDG component. For the service water system providing cooling to the EDGs, only the devices providing control of cooling flow to the EDG heat exchangers are included. Room heating and ventilating is not included.

The EDG failure modes include fail to start (FTS), fail to load and run for one hour (FTLR), and fail to run beyond one hour (FTR>1H). These failure modes were used in NUREG/CR-6928 and are similar to those used in the MSPI Program. There is some uncertainty concerning when the run hours should start to be counted; should they start as soon as the EDG starts or should they start only after the output circuit breaker has closed? For this study, the run hours start as soon as the EDG is started, which is the way data have been reported in EPIX.

Guidelines for determining whether a component event reported in EPIX is to be included in FTS, FTLR, or FTR>1H are similar to those used in the MSPI Program. In general, any circumstance in which the component is not able to meet the performance requirements defined in the probabilistic risk assessment (PRA) is counted. This includes conditions revealed through testing, operational demands, unplanned demands, or discovery. Also, run failures that occur beyond the typical 24-hour mission time in PRAs are included. However, certain events are excluded: slow engine starting times that do not exceed the PRA success criteria, conditions that are annunciated immediately in the control room without a demand, and run events that are shown to not have caused an actual run failure within 24 hours. Also, events occurring during maintenance or post-maintenance testing that are related to the actual maintenance activities are excluded. Finally, in contrast to the MSPI Program, a general guideline on slow starting times is to include only those slow starts requiring more than 20 seconds as FTS events, similar to what was done for the CCF database and the EDG system study. (In the MSPI Program, most licensees chose to use technical specification requirements for fast starts as their success criteria – typically less than 10 seconds to start.) All of the EDG events within EPIX were reviewed to ensure that they were binned to the correct failure mode – FTS, FTLR, FTR>1H, or no failure. However, even given detailed descriptions of failure events, this binning still required some judgment and involves some uncertainty.

Guidelines for counting demands and run hours are similar to those in the MSPI Program. Start and load/run demands include those resulting from tests, operational demands, and unplanned demands. Demands during maintenance and post-maintenance testing are excluded. Similarly, run hours include those from tests, operational demands, and unplanned demands. Note that the test demands and run hours dominate the totals, compared with operational and unplanned demands and run hours.

8 DATA TABLES

Table 14. Plot data for EPS EDG FTS industry trend. Figure 1

FY/ Source	Failures	Demands	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						2.56E-04	1.50E-02	5.00E-03
1998	16	4415.9	3.10E-03	2.15E-03	4.45E-03	2.27E-03	5.15E-03	3.60E-03
1999	12	4393.4	3.05E-03	2.22E-03	4.20E-03	1.60E-03	4.11E-03	2.74E-03
2000	10	4340.3	3.01E-03	2.27E-03	3.98E-03	1.28E-03	3.61E-03	2.33E-03
2001	11	4337.9	2.96E-03	2.32E-03	3.79E-03	1.45E-03	3.89E-03	2.55E-03
2002	15	4570.2	2.92E-03	2.35E-03	3.63E-03	2.03E-03	4.73E-03	3.27E-03
2003	19	4432.5	2.88E-03	2.35E-03	3.52E-03	2.78E-03	5.90E-03	4.24E-03
2004	13	4384.9	2.84E-03	2.33E-03	3.46E-03	1.77E-03	4.39E-03	2.96E-03
2005	16	4393.4	2.79E-03	2.27E-03	3.44E-03	2.28E-03	5.17E-03	3.62E-03
2006	11	4311.5	2.75E-03	2.19E-03	3.47E-03	1.46E-03	3.91E-03	2.57E-03
2007	6	4345.8	2.71E-03	2.09E-03	3.52E-03	6.51E-04	2.47E-03	1.44E-03
2008	15	4384.2	2.67E-03	1.98E-03	3.60E-03	2.11E-03	4.92E-03	3.40E-03
2009	8	4187.4	2.64E-03	1.88E-03	3.70E-03	9.93E-04	3.16E-03	1.95E-03
2010	15	4237.4	2.60E-03	1.77E-03	3.81E-03	2.18E-03	5.08E-03	3.52E-03

Table 15. Plot data for EPS EDG FTLR industry trend. Figure 2

FY/ Source	Failures	Demands	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						3.52E-04	7.81E-03	3.00E-03
1998	20	3992.4	3.12E-03	2.23E-03	4.37E-03	3.30E-03	6.87E-03	4.98E-03
1999	9	3912.5	3.23E-03	2.39E-03	4.35E-03	1.25E-03	3.72E-03	2.35E-03
2000	12	3956.3	3.33E-03	2.57E-03	4.33E-03	1.78E-03	4.59E-03	3.06E-03
2001	8	3805.1	3.44E-03	2.74E-03	4.33E-03	1.10E-03	3.50E-03	2.16E-03
2002	18	3880.8	3.56E-03	2.91E-03	4.35E-03	2.99E-03	6.48E-03	4.62E-03
2003	16	3782.2	3.68E-03	3.07E-03	4.41E-03	2.66E-03	6.03E-03	4.22E-03
2004	14	3833.4	3.80E-03	3.20E-03	4.51E-03	2.23E-03	5.35E-03	3.66E-03
2005	12	3818.2	3.93E-03	3.30E-03	4.67E-03	1.85E-03	4.75E-03	3.17E-03
2006	16	3716.0	4.06E-03	3.36E-03	4.89E-03	2.71E-03	6.14E-03	4.29E-03
2007	21	3700.2	4.19E-03	3.40E-03	5.17E-03	3.77E-03	7.70E-03	5.62E-03
2008	16	3726.6	4.33E-03	3.41E-03	5.50E-03	2.70E-03	6.12E-03	4.28E-03
2009	17	3612.8	4.47E-03	3.40E-03	5.88E-03	2.99E-03	6.62E-03	4.68E-03
2010	15	3708.2	4.62E-03	3.39E-03	6.30E-03	2.51E-03	5.84E-03	4.04E-03

Table 16. Plot data for EPS EDG FTR>1H industry trend. Figure 3

FY/ Source	Failures	Run Time (h)	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						1.42E-04	1.90E-03	8.00E-04
1998	3	7414.6	3.17E-04	1.67E-04	6.00E-04	1.38E-04	8.93E-04	4.44E-04
1999	0	7321.3	3.74E-04	2.11E-04	6.62E-04	2.53E-07	2.47E-04	6.42E-05
2000	5	8490.6	4.41E-04	2.66E-04	7.32E-04	2.55E-04	1.10E-03	6.14E-04
2001	4	8591.1	5.21E-04	3.34E-04	8.12E-04	1.84E-04	9.34E-04	4.97E-04
2002	6	9111.4	6.15E-04	4.18E-04	9.04E-04	3.08E-04	1.17E-03	6.79E-04
2003	8	8648.1	7.25E-04	5.20E-04	1.01E-03	4.76E-04	1.51E-03	9.33E-04
2004	9	8083.8	8.56E-04	6.39E-04	1.15E-03	5.92E-04	1.76E-03	1.11E-03
2005	12	8740.3	1.01E-03	7.76E-04	1.32E-03	7.94E-04	2.05E-03	1.36E-03
2006	9	7937.1	1.19E-03	9.23E-04	1.54E-03	6.02E-04	1.79E-03	1.13E-03
2007	13	8180.5	1.41E-03	1.08E-03	1.84E-03	9.34E-04	2.32E-03	1.56E-03
2008	14	8184.5	1.66E-03	1.23E-03	2.24E-03	1.02E-03	2.46E-03	1.68E-03
2009	16	8227.9	1.96E-03	1.39E-03	2.76E-03	1.20E-03	2.73E-03	1.90E-03
2010	16	8096.4	2.31E-03	1.55E-03	3.44E-03	1.22E-03	2.77E-03	1.93E-03

Table 17. Plot data for HPCS EDG FTS industry trend. Figure 4

FY/ Source	Failures	Demands	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						2.56E-04	1.50E-02	5.00E-03
1998	0	159.3	1.06E-03	6.16E-04	1.83E-03	3.54E-06	3.53E-03	9.18E-04
1999	1	177.8	1.07E-03	6.61E-04	1.73E-03	3.12E-04	6.93E-03	2.67E-03
2000	0	164.8	1.08E-03	7.07E-04	1.64E-03	3.50E-06	3.49E-03	9.09E-04
2001	0	139.5	1.09E-03	7.51E-04	1.57E-03	3.67E-06	3.66E-03	9.53E-04
2002	0	146.9	1.09E-03	7.90E-04	1.51E-03	3.62E-06	3.61E-03	9.40E-04
2003	0	156.1	1.10E-03	8.21E-04	1.48E-03	3.56E-06	3.55E-03	9.24E-04
2004	0	142.4	1.11E-03	8.37E-04	1.47E-03	3.65E-06	3.64E-03	9.48E-04
2005	0	134.4	1.12E-03	8.37E-04	1.49E-03	3.71E-06	3.70E-03	9.63E-04
2006	0	134.4	1.13E-03	8.21E-04	1.55E-03	3.71E-06	3.70E-03	9.63E-04
2007	0	126.1	1.14E-03	7.94E-04	1.62E-03	3.77E-06	3.76E-03	9.78E-04
2008	0	152.7	1.14E-03	7.60E-04	1.72E-03	3.58E-06	3.57E-03	9.30E-04
2009	1	131.0	1.15E-03	7.23E-04	1.84E-03	3.41E-04	7.56E-03	2.91E-03
2010	0	156.1	1.16E-03	6.84E-04	1.97E-03	3.56E-06	3.55E-03	9.24E-04

Table 18. Plot data for HPCS EDG FTLR industry trend. Figure 5

FY/ Source	Failures	Demands	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						3.52E-04	7.81E-03	3.00E-03
1998	0	116.2	2.37E-03	1.20E-03	4.68E-03	6.30E-06	6.42E-03	1.67E-03
1999	1	126.7	2.35E-03	1.29E-03	4.29E-03	5.68E-04	1.26E-02	4.87E-03
2000	0	131.7	2.33E-03	1.38E-03	3.96E-03	5.98E-06	6.11E-03	1.59E-03
2001	0	120.9	2.32E-03	1.46E-03	3.68E-03	6.20E-06	6.32E-03	1.65E-03
2002	1	128.6	2.30E-03	1.53E-03	3.46E-03	5.64E-04	1.25E-02	4.84E-03
2003	0	129.7	2.28E-03	1.57E-03	3.32E-03	6.02E-06	6.14E-03	1.60E-03
2004	1	130.7	2.27E-03	1.58E-03	3.25E-03	5.61E-04	1.24E-02	4.81E-03
2005	0	120.7	2.25E-03	1.55E-03	3.27E-03	6.20E-06	6.33E-03	1.65E-03
2006	0	122.7	2.24E-03	1.49E-03	3.36E-03	6.16E-06	6.29E-03	1.64E-03
2007	0	119.3	2.22E-03	1.40E-03	3.52E-03	6.23E-06	6.36E-03	1.65E-03
2008	0	139.8	2.20E-03	1.30E-03	3.73E-03	5.83E-06	5.95E-03	1.55E-03
2009	0	115.1	2.19E-03	1.20E-03	3.98E-03	6.32E-06	6.45E-03	1.68E-03
2010	1	134.6	2.17E-03	1.10E-03	4.28E-03	5.54E-04	1.23E-02	4.75E-03

Table 19. Plot data for HPCS EDG FTR>1H industry trend. Figure 6

FY/ Source	Failures	Run Time (h)	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						1.42E-04	1.90E-03	8.00E-04
1998	0	132.6	1.44E-03	8.35E-04	2.50E-03	5.01E-06	4.90E-03	1.28E-03
1999	1	209.2	1.47E-03	9.05E-04	2.38E-03	3.75E-04	8.34E-03	3.20E-03
2000	0	133.0	1.49E-03	9.77E-04	2.28E-03	5.01E-06	4.89E-03	1.27E-03
2001	0	114.6	1.52E-03	1.05E-03	2.20E-03	5.26E-06	5.13E-03	1.34E-03
2002	0	118.3	1.54E-03	1.11E-03	2.14E-03	5.20E-06	5.08E-03	1.32E-03
2003	0	183.0	1.57E-03	1.16E-03	2.11E-03	4.44E-06	4.34E-03	1.13E-03
2004	0	85.6	1.59E-03	1.19E-03	2.13E-03	5.70E-06	5.57E-03	1.45E-03
2005	1	169.2	1.62E-03	1.20E-03	2.19E-03	4.10E-04	9.12E-03	3.50E-03
2006	0	128.1	1.65E-03	1.19E-03	2.29E-03	5.07E-06	4.96E-03	1.29E-03
2007	0	98.9	1.68E-03	1.15E-03	2.44E-03	5.49E-06	5.36E-03	1.40E-03
2008	0	187.1	1.70E-03	1.11E-03	2.61E-03	4.40E-06	4.30E-03	1.12E-03
2009	0	112.1	1.73E-03	1.06E-03	2.82E-03	5.29E-06	5.17E-03	1.35E-03
2010	1	144.8	1.76E-03	1.01E-03	3.06E-03	4.35E-04	9.67E-03	3.71E-03

Table 20. Plot data for EPS EDG UA trend. Figure 7

FY/ Source	UA Hours	Critical Hours	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						4.10E-03	2.33E-02	1.20E-02
1998	16175.09	1641222	1.03E-02	7.15E-03	1.35E-02	5.25E-04	2.98E-02	1.00E-02
1999	23400.06	2213152	9.70E-03	7.61E-03	1.18E-02	1.27E-03	2.73E-02	1.06E-02
2000	18405.18	2228580	9.06E-03	6.98E-03	1.12E-02	1.27E-03	2.02E-02	8.24E-03
2001	19096.42	2209557	8.42E-03	5.23E-03	1.16E-02	5.28E-04	2.53E-02	8.68E-03
2002	24094.1	2153082.4	1.22E-02	1.04E-02	1.40E-02	1.11E-03	3.02E-02	1.12E-02
2003	28620.1	2115868.4	1.27E-02	1.12E-02	1.42E-02	6.28E-04	4.13E-02	1.37E-02
2004	31773.8	2168423.5	1.32E-02	1.19E-02	1.45E-02	1.06E-05	6.21E-02	1.47E-02
2005	25242.4	2123378.6	1.37E-02	1.26E-02	1.48E-02	1.26E-03	3.17E-02	1.20E-02
2006	29265.6	2163643.9	1.42E-02	1.32E-02	1.52E-02	8.58E-04	3.93E-02	1.36E-02
2007	32067.7	2156021.5	1.47E-02	1.37E-02	1.58E-02	1.17E-03	4.19E-02	1.50E-02
2008	35391.1	2153386.5	1.52E-02	1.40E-02	1.65E-02	1.32E-03	4.60E-02	1.65E-02
2009	33659.4	2151450.4	1.58E-02	1.42E-02	1.73E-02	2.20E-03	3.93E-02	1.57E-02
2010	16004.3	1036705.9	1.63E-02	1.44E-02	1.81E-02	2.65E-04	5.30E-02	1.56E-02

Table 21. Plot data for HPCS EDG UA trend. Figure 8

FY/ Source	UA Hours	Critical Hours	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
NUREG /CR-6928						5.23E-03	2.10E-02	1.20E-02
1998	156.9	29073.5	8.21E-03	6.94E-03	9.71E-03	8.42E-04	1.09E-02	4.62E-03
1999	781.8	53269.1	8.43E-03	7.27E-03	9.78E-03	1.54E-03	3.51E-02	1.35E-02
2000	932.7	64615.0	8.67E-03	7.61E-03	9.87E-03	7.12E-04	4.25E-02	1.42E-02
2001	427.3	64318.8	8.91E-03	7.95E-03	9.98E-03	9.05E-04	1.67E-02	6.65E-03
2002	443.5	65660.8	9.16E-03	8.28E-03	1.01E-02	5.22E-04	1.91E-02	6.80E-03
2003	795.9	64216.1	9.41E-03	8.59E-03	1.03E-02	5.50E-03	2.16E-02	1.24E-02
2004	848.0	66422.6	9.67E-03	8.85E-03	1.06E-02	3.55E-03	2.64E-02	1.27E-02
2005	635.1	63863.9	9.94E-03	9.07E-03	1.09E-02	1.94E-03	2.21E-02	9.65E-03
2006	524.1	66916.8	1.02E-02	9.24E-03	1.13E-02	2.12E-03	1.62E-02	7.74E-03
2007	593.1	64802.1	1.05E-02	9.37E-03	1.18E-02	3.72E-03	1.63E-02	9.07E-03
2008	779.2	65346.3	1.08E-02	9.48E-03	1.23E-02	9.81E-04	3.38E-02	1.22E-02
2009	506.8	64536.4	1.11E-02	9.57E-03	1.29E-02	1.12E-03	1.92E-02	7.74E-03
2010	1063.7	65868.9	1.14E-02	9.64E-03	1.35E-02	2.17E-03	4.03E-02	1.60E-02

Table 22. Plot data for EPS EDG unreliability trend. Figure 9

FY	Regression Curve Data Points			Plot Trend Error Bar Points		
	Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	1.60E-02	1.24E-02	1.96E-02	1.05E-02	2.06E-02	1.44E-02
1999	1.82E-02	1.50E-02	2.13E-02	7.33E-03	4.10E-02	1.93E-02
2000	2.03E-02	1.76E-02	2.31E-02	1.26E-02	5.45E-02	2.60E-02
2001	2.25E-02	2.01E-02	2.50E-02	1.08E-02	2.65E-02	1.66E-02
2002	2.47E-02	2.25E-02	2.68E-02	1.55E-02	3.38E-02	2.19E-02
2003	2.69E-02	2.49E-02	2.88E-02	2.42E-02	4.05E-02	3.13E-02
2004	2.90E-02	2.71E-02	3.09E-02	2.30E-02	4.59E-02	3.22E-02
2005	3.12E-02	2.92E-02	3.32E-02	2.38E-02	4.43E-02	3.17E-02
2006	3.34E-02	3.12E-02	3.55E-02	2.20E-02	3.64E-02	2.79E-02
2007	3.56E-02	3.31E-02	3.80E-02	2.84E-02	4.16E-02	3.40E-02
2008	3.77E-02	3.50E-02	4.05E-02	2.79E-02	6.15E-02	3.95E-02
2009	3.99E-02	3.67E-02	4.31E-02	2.94E-02	4.77E-02	3.63E-02
2010	4.21E-02	3.85E-02	4.57E-02	3.23E-02	7.03E-02	4.64E-02

Table 23. Plot data for HPCS EDG unreliability trend. Figure 10

FY	Regression Curve Data Points			Plot Trend Error Bar Points		
	Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	2.47E-02	2.13E-02	2.85E-02	1.15E-02	5.82E-02	2.42E-02
1999	2.53E-02	2.23E-02	2.88E-02	3.12E-02	5.95E-02	4.17E-02
2000	2.60E-02	2.32E-02	2.91E-02	1.27E-02	3.34E-02	2.05E-02
2001	2.66E-02	2.41E-02	2.94E-02	1.25E-02	3.96E-02	2.13E-02
2002	2.73E-02	2.50E-02	2.98E-02	1.61E-02	4.57E-02	2.64E-02
2003	2.80E-02	2.59E-02	3.03E-02	1.10E-02	5.24E-02	2.41E-02
2004	2.87E-02	2.66E-02	3.10E-02	1.55E-02	7.80E-02	3.07E-02
2005	2.95E-02	2.72E-02	3.19E-02	2.79E-02	5.90E-02	3.92E-02
2006	3.02E-02	2.77E-02	3.30E-02	1.24E-02	5.15E-02	2.54E-02
2007	3.10E-02	2.81E-02	3.42E-02	1.36E-02	5.49E-02	2.76E-02
2008	3.18E-02	2.84E-02	3.56E-02	1.17E-02	5.61E-02	2.70E-02
2009	3.26E-02	2.87E-02	3.70E-02	1.61E-02	5.37E-02	3.00E-02
2010	3.34E-02	2.89E-02	3.86E-02	3.25E-02	7.45E-02	4.69E-02

Table 24. Plot data for EPS and HPCS EDG start demands trend. Figure 11

FY/ Source	Demands	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	4575	94.0	4.90E+01	4.79E+01	5.01E+01	4.75E+01	4.99E+01	4.87E+01
1999	4571	94.0	4.88E+01	4.79E+01	4.98E+01	4.75E+01	4.98E+01	4.86E+01
2000	4505	94.3	4.86E+01	4.78E+01	4.95E+01	4.66E+01	4.90E+01	4.78E+01
2001	4477	94.0	4.85E+01	4.77E+01	4.92E+01	4.65E+01	4.88E+01	4.76E+01
2002	4717	94.0	4.83E+01	4.77E+01	4.89E+01	4.90E+01	5.14E+01	5.02E+01
2003	4589	94.0	4.81E+01	4.75E+01	4.87E+01	4.76E+01	5.00E+01	4.88E+01
2004	4527	94.3	4.80E+01	4.74E+01	4.85E+01	4.69E+01	4.92E+01	4.80E+01
2005	4528	94.0	4.78E+01	4.72E+01	4.84E+01	4.70E+01	4.94E+01	4.82E+01
2006	4446	94.0	4.76E+01	4.70E+01	4.83E+01	4.61E+01	4.85E+01	4.73E+01
2007	4472	94.0	4.75E+01	4.67E+01	4.82E+01	4.64E+01	4.88E+01	4.76E+01
2008	4537	94.3	4.73E+01	4.65E+01	4.81E+01	4.70E+01	4.93E+01	4.81E+01
2009	4318	94.0	4.71E+01	4.62E+01	4.81E+01	4.48E+01	4.71E+01	4.59E+01
2010	4393	94.0	4.70E+01	4.59E+01	4.80E+01	4.56E+01	4.79E+01	4.67E+01

Table 25. Plot data for EPS and HPCS EDG load and run ≤1-hour demands trend. Figure 12

FY/ Source	Demands	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	4109	94.0	4.34E+01	4.28E+01	4.41E+01	4.26E+01	4.48E+01	4.37E+01
1999	4039	94.0	4.31E+01	4.26E+01	4.38E+01	4.19E+01	4.41E+01	4.30E+01
2000	4088	94.3	4.29E+01	4.23E+01	4.34E+01	4.23E+01	4.45E+01	4.34E+01
2001	3926	94.0	4.26E+01	4.21E+01	4.30E+01	4.07E+01	4.29E+01	4.18E+01
2002	4009	94.0	4.23E+01	4.19E+01	4.27E+01	4.15E+01	4.38E+01	4.26E+01
2003	3912	94.0	4.20E+01	4.17E+01	4.24E+01	4.05E+01	4.27E+01	4.16E+01
2004	3964	94.3	4.18E+01	4.14E+01	4.21E+01	4.10E+01	4.32E+01	4.21E+01
2005	3939	94.0	4.15E+01	4.11E+01	4.19E+01	4.08E+01	4.30E+01	4.19E+01
2006	3839	94.0	4.12E+01	4.08E+01	4.16E+01	3.98E+01	4.19E+01	4.08E+01
2007	3819	94.0	4.09E+01	4.05E+01	4.14E+01	3.96E+01	4.17E+01	4.06E+01
2008	3866	94.3	4.07E+01	4.02E+01	4.12E+01	3.99E+01	4.21E+01	4.10E+01
2009	3728	94.0	4.04E+01	3.98E+01	4.10E+01	3.86E+01	4.07E+01	3.97E+01
2010	3843	94.0	4.02E+01	3.95E+01	4.08E+01	3.98E+01	4.20E+01	4.09E+01

Table 26. Plot data for EPS and HPCS EDG run hours (greater than 1H) trend. Figure 13

FY/ Source	Run Hours	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	7636	94.0	8.84E+01	8.19E+01	9.54E+01	7.97E+01	8.28E+01	8.12E+01
1999	7630	94.0	8.87E+01	8.29E+01	9.48E+01	7.96E+01	8.27E+01	8.12E+01
2000	8726	94.3	8.89E+01	8.38E+01	9.43E+01	9.10E+01	9.42E+01	9.26E+01
2001	8802	94.0	8.92E+01	8.47E+01	9.39E+01	9.20E+01	9.53E+01	9.36E+01
2002	9326	94.0	8.95E+01	8.55E+01	9.36E+01	9.75E+01	1.01E+02	9.92E+01
2003	8940	94.0	8.97E+01	8.61E+01	9.35E+01	9.35E+01	9.68E+01	9.51E+01
2004	8277	94.3	9.00E+01	8.65E+01	9.37E+01	8.62E+01	8.94E+01	8.78E+01
2005	9013	94.0	9.03E+01	8.66E+01	9.41E+01	9.42E+01	9.75E+01	9.59E+01
2006	8159	94.0	9.05E+01	8.65E+01	9.47E+01	8.52E+01	8.84E+01	8.68E+01
2007	8378	94.0	9.08E+01	8.63E+01	9.55E+01	8.75E+01	9.07E+01	8.91E+01
2008	8504	94.3	9.11E+01	8.59E+01	9.65E+01	8.86E+01	9.18E+01	9.02E+01
2009	8449	94.0	9.13E+01	8.54E+01	9.76E+01	8.83E+01	9.15E+01	8.99E+01
2010	8373	94.0	9.16E+01	8.49E+01	9.88E+01	8.75E+01	9.07E+01	8.91E+01

Table 27. Plot data for EPS and HPCS EDG FTS events trend. Figure 14

FY/ Source	Failures	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	16	94.0	1.47E-01	1.03E-01	2.11E-01	1.07E-01	2.43E-01	1.69E-01
1999	13	94.0	1.45E-01	1.06E-01	1.99E-01	8.27E-02	2.05E-01	1.38E-01
2000	10	94.3	1.43E-01	1.08E-01	1.88E-01	5.92E-02	1.67E-01	1.07E-01
2001	11	94.0	1.40E-01	1.10E-01	1.79E-01	6.71E-02	1.80E-01	1.18E-01
2002	15	94.0	1.38E-01	1.11E-01	1.71E-01	9.88E-02	2.30E-01	1.59E-01
2003	19	94.0	1.36E-01	1.11E-01	1.65E-01	1.32E-01	2.80E-01	2.00E-01
2004	13	94.3	1.33E-01	1.10E-01	1.62E-01	8.25E-02	2.05E-01	1.38E-01
2005	16	94.0	1.31E-01	1.07E-01	1.61E-01	1.07E-01	2.43E-01	1.69E-01
2006	11	94.0	1.29E-01	1.03E-01	1.62E-01	6.71E-02	1.80E-01	1.18E-01
2007	6	94.0	1.27E-01	9.80E-02	1.64E-01	3.02E-02	1.15E-01	6.66E-02
2008	15	94.3	1.25E-01	9.29E-02	1.67E-01	9.85E-02	2.30E-01	1.58E-01
2009	9	94.0	1.23E-01	8.77E-02	1.71E-01	5.18E-02	1.54E-01	9.73E-02
2010	15	94.0	1.21E-01	8.25E-02	1.76E-01	9.88E-02	2.30E-01	1.59E-01

Table 28. Plot data for EPS EDG FTLR events trend. Figure 15

FY/ Source	Failures	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	20	94.0	1.35E-01	9.68E-02	1.88E-01	1.41E-01	2.93E-01	2.11E-01
1999	10	94.0	1.38E-01	1.03E-01	1.85E-01	5.97E-02	1.68E-01	1.08E-01
2000	12	94.3	1.42E-01	1.10E-01	1.83E-01	7.51E-02	1.93E-01	1.28E-01
2001	8	94.0	1.45E-01	1.16E-01	1.82E-01	4.47E-02	1.42E-01	8.76E-02
2002	19	94.0	1.49E-01	1.22E-01	1.82E-01	1.32E-01	2.81E-01	2.01E-01
2003	16	94.0	1.53E-01	1.28E-01	1.83E-01	1.07E-01	2.44E-01	1.70E-01
2004	15	94.3	1.57E-01	1.33E-01	1.86E-01	9.90E-02	2.31E-01	1.59E-01
2005	12	94.0	1.61E-01	1.36E-01	1.91E-01	7.53E-02	1.94E-01	1.29E-01
2006	16	94.0	1.65E-01	1.37E-01	1.99E-01	1.07E-01	2.44E-01	1.70E-01
2007	21	94.0	1.69E-01	1.38E-01	2.08E-01	1.49E-01	3.05E-01	2.21E-01
2008	16	94.3	1.74E-01	1.37E-01	2.20E-01	1.07E-01	2.43E-01	1.70E-01
2009	17	94.0	1.78E-01	1.36E-01	2.33E-01	1.16E-01	2.56E-01	1.80E-01
2010	16	94.0	1.83E-01	1.35E-01	2.48E-01	1.07E-01	2.44E-01	1.70E-01

Table 29. Plot data for EPS EDG FTR>1H events trend. Figure 16

FY/ Source	Failures	Reactor Years	Regression Curve Data Points			Plot Trend Error Bar Points		
			Mean	Lower (5%)	Upper (95%)	Lower (5%)	Upper (95%)	Mean
1998	3	94.0	3.32E-02	2.19E-02	5.03E-02	1.09E-02	7.09E-02	3.53E-02
1999	1	94.0	3.85E-02	2.66E-02	5.58E-02	1.77E-03	3.94E-02	1.51E-02
2000	5	94.3	4.46E-02	3.21E-02	6.19E-02	2.30E-02	9.89E-02	5.53E-02
2001	4	94.0	5.17E-02	3.88E-02	6.90E-02	1.68E-02	8.53E-02	4.54E-02
2002	6	94.0	5.99E-02	4.67E-02	7.70E-02	2.97E-02	1.13E-01	6.55E-02
2003	8	94.0	6.95E-02	5.59E-02	8.63E-02	4.37E-02	1.39E-01	8.57E-02
2004	9	94.3	8.05E-02	6.65E-02	9.75E-02	5.09E-02	1.52E-01	9.55E-02
2005	13	94.0	9.33E-02	7.83E-02	1.11E-01	8.14E-02	2.02E-01	1.36E-01
2006	9	94.0	1.08E-01	9.11E-02	1.28E-01	5.10E-02	1.52E-01	9.58E-02
2007	13	94.0	1.25E-01	1.04E-01	1.50E-01	8.14E-02	2.02E-01	1.36E-01
2008	14	94.3	1.45E-01	1.18E-01	1.78E-01	8.90E-02	2.14E-01	1.46E-01
2009	16	94.0	1.68E-01	1.33E-01	2.13E-01	1.05E-01	2.39E-01	1.66E-01
2010	16	94.0	1.95E-01	1.49E-01	2.56E-01	1.05E-01	2.39E-01	1.66E-01

9 REFERENCES

1. S.A. Eide, et al, *Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, NUREG/CR-6928, February 2007.

2. C.L. Atwood, et al. *Handbook of Parameter Estimation for Probabilistic Risk Assessment*, NUREG/CR-6823, September 2003.

Table 1- SDP PHASE 1 SCREENING WORKSHEET FOR ALL CORNERSTONES
Reference/Title (LER #, Inspection Report #, etc): 05000413/2012009, 05000414/2012009
Performance Deficiency (concise statement clearly stating deficient licensee performance): The licensee failed to follow the requirements of EDM 141 for providing appropriate design information to the vendor for programming the Zone G digital processors.
Factual Description of Condition (statement of facts known about the condition that resulted from the performance deficiency, without hypothetical failures included.) Explain why issue is more than minor: A Zone G modification was conducted during 1EOC19 to replace electro-mechanical and static main generator relays with multifunction, microprocessor-based relays. One of the relaying functions was an underfrequency relay to protect the turbine generator by opening the switchyard breakers connected to the generator output. The "off-line" block was omitted by the relay vendor for the instantaneous underfrequency relay function due to an error in the programming for the modification. The omission would cause a LOOP following any event or transient from 100% power that causes a reactor/turbine trip.
System(s)/Train(s) Degraded by Condition or Programmatic Weakness (note that the safety functions affected must be those identified in the Site Specific Risk-Informed Inspection Notebooks): Offsite Power - Consisting of two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System.
Licensing Basis Function of System(s)/Train(s) or Program: An offsite power system and an onsite power system are provided for each unit at the Catawba Nuclear Station to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safety Features Systems during abnormal and accident conditions. Each Catawba Unit is connected to a common 230kV switchyard and thereby to the Duke 230kV transmission system via two separate and independent transmission lines.
Other Safety Function of System(s)/Train(s): N/A
Maintenance Rule Category (check one): _X_ risk-significant ____ non risk-significant
Time condition existed or is assumed to have existed: Condition existed from June 11, 2011, when Unit 1 reached 100% power following the Zone G relay modification, until April 4, 2012, when the event occurred. (298 days)

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Table 2 - CORNERSTONES AND FUNCTIONS DEGRADED AS A RESULT OF DEFICIENCY (✔) Check the appropriate boxes		
INITIATING EVENTS CORNERSTONE	**MITIGATION SYSTEMS CORNERSTONE**	**BARRIERS CORNERSTONE**
☐ Primary System LOCA initiator contributor - (e.g., RCS leakage from pressurizer heater sleeves, RPV piping penetrations, CRDM nozzles, PORVs, SRVs, ISLOCA issues, etc.) ☐ Transient initiator contributor (e.g., reactor/turbine trip, loss of offsite power, loss of service water, main steam/feedwater piping degradations, etc.) ☐ Fire initiator contributor (e.g., transient loadings and combustibles, hotwork) ☐ Internal/external flooding initiator contributor	☒ Core Decay Heat Removal Degraded ☒ Short Term Heat Removal Degraded ☒ Primary (e.g., Safety Inj, [main feedwater, HPCI, and RCIC - BWR only]) _X_ High Pressure _X_ Low Pressure ☐ Secondary - PWR only (e.g. AFW, main feedwater, ADVs) ☐ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool) ☐ Reactivity Control Degraded ☐ Seismic/Fire/Flood/Severe Weather Protection Degraded	☐ RCS Boundary as a mitigator following plant upset (e.g., pressurized thermal shock). Note: all other RCS boundary issues, such as leaks, will be considered under the Initiating Events Cornerstone. ☐ Containment Barrier Degraded ☐ Reactor Containment Degraded ___ Actual Breach or Bypass ___ Heat Removal, Hydrogen or Pressure Control Degraded ☐ Control Room, Aux Bldg/Reactor Bldg, or Spent Fuel Bldg Barrier Degraded ☐ Fuel Cladding Barrier Degraded ☐ Spent Fuel Pool ☐ Spent Fuel Pool Boiling ☐ Fuel Handling ☐ Spent Fuel Pool Inventory
EMERGENCY PREPAREDNESS CORNERSTONE	**OCCUPATION RADIATION SAFETY CORNERSTONE**	**PUBLIC RADIATION SAFETY CORNERSTONE**
☐ Failure to Comply with a Planning Standard or Risk-Significant Planning Standard ☐ Actual Event Implementation Problem	☐ ALARA Planning or Work Controls ☐ Exposure or Over-exposure problem ☐ Ability to Assess Dose Compromised	☐ Radioactive Effluent Release Program ☐ Radioactive Environmental Monitoring Program ☐ Radioactive Material Control Program ☐ Transportation or Part 61
SECURITY CORNERSTONE		
☐ Findings identified under the IMC-2201, Security and Safeguards Inspection Program		

Table 3a - SDP PHASE 1 SCREENING WORKSHEET FOR EMERGENCY PREPAREDNESS, OCCUPATIONAL & PUBLIC RADIATION, AND SECURITY CORNERSTONES
IF the finding is in the licensee's: 1. emergency preparedness area, **THEN STOP. Go to** IMC 0609, Appendix B. 2. occupational radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix C. 3. public radiation safety area, **THEN STOP. Go to** IMC 0609, Appendix D. 4. security area, **THEN STOP. Go to** IMC 0609, Appendix E.

Table 3b - SDP PHASE 1 SCREENING WORKSHEET FOR INITIATING EVENTS, MITIGATION SYSTEMS, AND BARRIERS CORNERSTONES
IF the finding affects: 1. fire protection defense-in-depth strategies involving: detection, suppression (equipment for both manual and automatic), barriers, fire prevention and administrative controls, and post fire safe shutdown systems, **THEN STOP. Go to** IMC 0609, Appendix F. Issues related to performance of the fire brigade are not included in Appendix F and require NRC management review using Appendix M. 2. the safety of a reactor during refueling outages, forced outages, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated, **THEN STOP. Go to** IMC 0609, Appendix G. 3. the operator licensing requalification program or simulator fidelity, **THEN STOP. Go to** IMC 0609, Appendix I. 4. steam generator tube integrity, **THEN STOP. Go to** IMC 0609, Appendix J. 5. the licensee's assessment and management of risk associated with performing maintenance activities under all plant operating or shutdown conditions in accordance with Baseline Inspection Procedure (IP) 71111.13, "Maintenance Risk Assessment and Emergent Work Control," **THEN STOP. Go to** IMC 0609, Appendix K. 6. SSCs where existing SDP guidance is not adequate to provide reasonable estimates of the findings significance within the established SDP timeliness goal of 90 days, **THEN STOP. Go to** IMC 0609, Appendix M. 7. the safety of an operating reactor, **THEN IDENTIFY** the degraded cornerstone(s): ☐ Initiating Event ☒ Mitigation Systems ☐ RCS Barrier (e.g., PTS issues) ☐ Fuel Barrier ☐ Containment Barriers **CONTINUE** to the appropriate column in Table 4a - Characterization Worksheet. NOTE: When assessing the significance of a finding affecting multiple cornerstones, the finding should be assigned to the cornerstone that best reflects the dominant risk of the finding.

Table 4a - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES

Initiating Events Cornerstone	Mitigation Systems Cornerstone	RCS or Fuel Barrier	Containment Barrier
LOCA Initiators 1. Assuming worst case degradation, would the finding result in exceeding the Tech Spec limit for any RCS leakage or could the finding have likely affected other mitigation systems resulting in a total loss of their safety function. ☐ **If YES →Stop. Go to Appendix A.** ☐ If NO, screen as Green. Transient Initiators 1. 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→Stop. Go to Appendix A.** ☐ If NO, screen as Green. External Event Initiators 1. 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 confirmed not to result in loss of operability or functionality.[1] ☐ **If YES, screen as Green.** ☒ If NO, continue. 2. Does the finding represent a loss of system safety function? ☒ **If YES →Stop. Go to Appendix A.** ☐ If NO, continue. 3. Does the finding represent actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time? ☐ **If YES → Stop. Go to Appendix A.** ☐ 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 → Stop. Go to Appendix A.** ☐ If NO, continue. 5. Does the finding screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event, using the criteria on page 5 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.	RCS Barrier (e.g., pressurized thermal shock issues) ☐ **Stop. Go to Phase 3**. Fuel Barrier ☐ Stop. Screen as Green. Spent Fuel Pool Issues 1. Does the finding result in loss of cooling to the spent fuel pool, whereby operator or equipment failures could preclude restoration of cooling prior to pool boiling? ☐ **If YES** → Stop. Go to **Appendix M.** ☐ If NO, continue. 2. Does the finding result from fuel handling errors that caused damage to fuel clad integrity or a dropped assembly (includes ISFSI)? ☐ **If YES** → Stop. Go to **Appendix M**. ☐ If NO, continue. 3. Does the finding result in a loss of spent fuel pool inventory greater than 10% of SFP volume? ☐ **If YES** → Stop. Go to **Appendix A**. ☐ If NO, screen as Green.	1. Does the finding only represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, or SBGT system (BWR)? ☐ **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 → Stop. Go to Phase 3.** ☐ If NO, continue. 3. Does the finding represent an actual open pathway in the physical integrity of reactor containment (valves, airlocks, containment isolation system (logic and instrumentation), and heat removal components? ☐ **If YES → Stop. Go to Appendix H.** ☐ If NO, continue. 4. Does the finding involve an actual reduction in function of hydrogen ignitors in the reactor containment? ☐ **If YES → Stop. Go to Appendix H.** ☐ If NO, screen as Green.

[1] per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment."

Table 4b - CHARACTERIZATION WORKSHEET FOR IE, MS, and BI CORNERSTONES
Seismic, 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)? ☐ **If YES** ➛ continue to question 2 ☐ If NO ➛ skip to question 3 2. If the equipment or safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of this 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 **two or more** Trains of a multi-train safety system or function; c) would degrade one or more Trains of a system that supports a safety system or function. ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet ☐ If NO, screen as Green 3. Does the finding involve the total 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, flooding, or severe weather event)? ☐ **If YES** ➛the finding is potentially risk significant due to external initiating event core damage sequences - return to Table 4a - Characterization Worksheet ☐ If NO, screen as Green
Result of Phase 1 screening process: ☐ **Screen as Green** ☒ **Go to Phase 2** ☐ **Go to Phase 3** Important Assumptions: Due to Zone G modification, any transient on Unit 1 from 100% power which causes a reactor/turbine trip would cause a loss of offsite power. Offsite Power considered a "mitigating system" in this analysis rather than an initiator since it supplies the Onsite Essential Auxiliary Power distribution system and associated mitigating systems. The loss of offsite power represents a loss of system safety function. Performed by: Eric Stamm Date: 6/14/2012