UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E. LAMAR BLVD.
ARLINGTON, TX 76011-4511

October 3, 2016

EA-16-168

Mr. Edward D. Halpin
Senior Vice President
and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 56, Mail Code 104/6
Avila Beach, CA 93424

SUBJECT: DIABLO CANYON POWER PLANT – NRC INSPECTION REPORT 05000275/2016010 AND 05000323/2016010; PRELIMINARY WHITE FINDING

Dear Mr. Halpin:

On September 12, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Diablo Canyon Power Plant. On the same date, the NRC inspectors discussed the results of this inspection with you and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

The enclosed inspection report discusses a finding that has preliminarily been determined to be of low to moderate safety significance (White) that may require additional NRC inspections, regulatory actions, and oversight. As described in Section 4OA2 of this report, the finding is associated with an apparent violation of Technical Specification 5.4.1.a, "Procedures," for the failure to develop adequate instructions for the installation of external limit switches on motor-operated valves. Specifically, Pacific Gas and Electric (PG&E) failed to provide adequate maintenance instructions for ensuring that these limit switches were operated within the vendor established overtravel settings. Consequently, the external limit switch for valve RHR-2-8700B, Unit 2 residual heat removal pump 2-2 suction from the refueling water storage tank, was installed such that the limit switch was operated beyond the overtravel setting resulting in a sheared internal roll pin causing the limit switch to fail. The failure of this limit switch resulted in failure of an input into the open permissive input logic for valve SI-2-8982B, Unit 2 train B residual heat removal suction from the containment recirculation sump. PG&E restored valve RHR-2-8700B to operable and replaced affected components, including the limit switch. PG&E also initiated corrective actions to develop more detailed and appropriate instructions for installing Namco™ Snap Lock position switches.

This finding was assessed based on the best available information using the applicable Significance Determination Process (SDP). The basis for the NRC's preliminary significance determination is described in the enclosed report. The NRC performed a detailed risk evaluation and determined the total resulting incremental conditional core damage probability for internal and external initiators. Considering the failure mechanism was introduced during Refueling Outage 2R17 maintenance in February 2013, and the limit switch was last successfully tested on October 22, 2014, the NRC evaluated the issue for the period from October 22, 2014, until the limit switch failure became apparent on May 16, 2016. This analysis resulted in a preliminary estimate of core damage frequency of 7.6E-06/year, corresponding to a finding of low to moderate risk significance (White). The NRC will inform you in writing when the final significance has been determined.

The finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the Enforcement Policy, which can be found on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. In accordance with NRC Inspection Manual Chapter 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The significance determination process encourages an open dialogue between the NRC staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, we are providing you with an opportunity to (1) attend a Regulatory Conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 40 days of the receipt of this letter, and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. The focus of the Regulatory Conference is to discuss the significance of the finding and not necessarily the root cause or corrective actions associated with the finding. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 40 days of your receipt of this letter. If you decline to request a Regulatory Conference or to submit a written response, you relinquish your right to appeal the final SDP determination, in that by not doing either, you fail to meet the appeal requirements stated in the Prerequisite and Limitation sections of Attachment 2 of NRC Inspection Manual Chapter 0609.

Please contact Jeremy Groom at (817) 200-1148 and in writing within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. The final resolution of this matter will be conveyed in separate correspondence.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room and in the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Troy W. Pruett, Director
Division of Reactor Projects

Docket Nos. 50-275 and 50-323
License Nos. DPR-80 and DPR-82

Enclosure:
Inspection Report 05000275/2016010 and
05000323/2016010
w/ Attachments:
1. Supplemental Information
2. Significance Determination

cc w/ enclosure: Electronic Distribution

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room and in the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

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DISTRIBUTION:
See next page

ADAMS ACCESSION NUMBER: ML16277A340

☒ SUNSI Review By: JRG		ADAMS ☒ Yes ☐ No	☒ Non-Sensitive ☐ Sensitive	☒ Publicly Available ☐ Non-Publicly Available		Keyword: NRC-002	
OFFICE	SRI:DRP/A	RI:DRP/A	SPE:DRP/A	DRS:SRA	TL:ACES	D:DRS	RC:ORA
NAME	CNewport	JReynoso	RAlexander	RDeese	MHay	AVegel	KFuller
SIGNATURE	/RA/	/RA/	/RA/	/RA/	/RA/	/RA/	/RA/
DATE	09/14/16	09/14/16	09/08/16	09/09/16	09/19/16	09/27/16	09/22/16
OFFICE	BC:DRP/A	D:DRP					
NAME	JGroom	TPruett					
SIGNATURE	/RA/	/RA/					
DATE	09/26/16	10/3/16					

OFFICIAL RECORD COPY

Letter to Edward D. Halpin from Troy W. Pruett dated October 3, 2016

SUBJECT: DIABLO CANYON POWER PLANT – NRC FOCUSED BASELINE INSPECTION REPORT 05000275/2016010 AND 05000323/2016010; PRELIMINARY WHITE FINDING

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000275; 05000323
License:	DPR-80; DPR-82
Report:	05000275/2016010; 05000323/2016010
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, CA
Dates:	May 16 through September 12, 2016
Inspectors:	C. Newport, Senior Resident Inspector J. Reynoso, Acting Senior Resident Inspector T. Sullivan, Project Engineer R. Deese, Senior Reactor Analyst
Approved By:	Troy W. Pruett, Director Division of Reactor Projects

SUMMARY

IR 05000275/2016010, 05000323/2016010; 05/16/2016 – 09/12/2016; Diablo Canyon Power Plant; Problem Identification and Resolution

The inspection activities described in this report were performed between May 16 and September 12, 2016, by the resident inspectors at Diablo Canyon Power Plant and inspectors from the NRC's Region IV office. The inspectors identified a preliminary White finding associated with an apparent violation of NRC requirements. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, "Significance Determination Process," issued April 29, 2015. Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, "Aspects within the Cross-Cutting Areas," issued December 4, 2014. Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Cornerstone: Mitigating Systems

- Preliminary White. The inspectors identified a preliminary White finding associated with an apparent violation of Technical Specification 5.4.1.a, "Procedures," for the licensee's failure to develop adequate instructions for the installation, adjustment, and testing of Namco™ Model EA170 snap lock limit switches. Specifically, the licensee failed to provide site-specific instructions for limiting the travel of these external limit switches when installed on safety-related motor operated valves. Consequently, the lever switch actuator for valve RHR-2-8700B, residual heat removal pump 2-2 suction from the refueling water storage tank, was installed such that the limit switch was operated repeatedly in an over-travel condition resulting in a sheared internal roll pin that ultimately caused the limit switch to fail. Following identification of this issue, the licensee replaced the limit switch for valve RHR-2-8700B and implemented actions to modify maintenance procedures for installing, calibrating, and testing motor-operated valve external limit switches. The licensee entered this issue into their corrective action program as Notification 50852345.

  The performance deficiency is more than minor, and therefore a finding, because it is associated with the procedure quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, maintenance procedure MP E-53.10R, "Augmented Stem Lubrication for Limitorque Operated Valves," used to perform limit switch adjustments on the Unit 2 valve RHR-2-8700B, did not provide adequate acceptance criteria to prevent overtravel of the limit switch actuating lever. This resulted in a subsequent failure of the limit switch, preventing the open permissive signal for valve SI-2-8982B, residual heat removal pump 2-2 suction from the containment recirculation sump, used during the emergency core cooling system (ECCS) recirculation mode. The inspectors evaluated the finding using the Attachment 0609.04, "Initial Characterization of Findings," worksheet to Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," issued June 19, 2012. The attachment instructs the inspectors to utilize IMC 0609, Appendix A, "Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012. In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," the inspectors determined that the finding required a detailed risk evaluation because it represented an actual loss of function of the train B ECCS for greater

than its technical specification allowed outage time. A senior reactor analyst performed a detailed risk evaluation in accordance with IMC 0609, Appendix A, Section 6.0, “Detailed Risk Evaluation.” The calculated increase in core damage frequency was dominated by small and medium loss of coolant accident initiators with failures of the opposite train of ECCS or related support systems. The analyst did not evaluate the large early release frequency because this performance deficiency would not have challenged the containment. The NRC preliminarily determined that the increase in core damage frequency for internal and external initiators was 7.6E-06/year, a finding of low to moderate risk significance (White). The inspector did not identify a cross-cutting aspect with this finding because it was not reflective of current performance. The inadequate procedure was developed in 2011 and did not reflect the licensee’s current performance related to procedure development. (Section 4OA2)

REPORT DETAILS

4. OTHER ACTIVITIES

Cornerstone: Mitigating Systems

4OA2 Problem Identification and Resolution (71152)

Annual Follow-up of Selected Issues

a. Inspection Scope

On May 16, 2016, during performance of surveillance procedure PEP V-7B, "Test of ECCS Valve Interlocks," Revision 9, valve SI-2-8982B, Unit 2 residual heat removal (RHR) pump 2-2 suction from the containment recirculation sump, failed to open from the main control room. Subsequent review determined that external limit switch, POS-648, for valve RHR-2-8700B, RHR 2-2 suction from the refueling water storage tank (RWST), was in a failed position. The failure of this limit switch prevented the open permissive signal for valve SI-2-8982B. Investigation by the licensee concluded that limit switch POS-648 failed due to a sheared internal roll pin.

The inspectors assessed the licensee's problem identification threshold, cause analyses, and verified that corrective actions were commensurate with the significance of the issue, appropriately prioritized and that these actions were adequate to correct the condition. The inspectors also reviewed the licensee's use of operating experience and their incorporation of vendor guidance into site-specific maintenance procedures.

These activities constituted completion of one annual follow-up sample as defined in Inspection Procedure 71152.

b. Findings

Failure to Establish Adequate Work Instructions for Installation of Namco™ Snap Lock Limit Switches

Introduction. The inspectors identified a preliminary White finding associated with an apparent violation of Technical Specification 5.4.1.a, "Procedures," for the licensee's failure to develop adequate instructions for the installation, adjustment and testing of Namco™ Model EA170 snap lock limit switches. Specifically, the licensee failed to provide site-specific instructions for limiting the travel of these external limit switches when installed on safety-related motor operated valves. Consequently, the lever switch actuator for valve RHR-2-8700B was installed such that the limit switch was operated repeatedly in an over-travel condition resulting in a sheared internal roll pin that ultimately caused the limit switch to fail.

Description. On May 16, 2016, the licensee performed surveillance procedure PEP V-7B, "Test of ECCS Valve Interlocks," Revision 9, to test various interlock and permissive circuits for the emergency core cooling system (ECCS). One interlock test involved valve circuitry needed to transfer the RHR pump suction from the RWST to the containment recirculation sump during the ECCS recirculation mode. During a loss of coolant accident, operators would implement ECCS recirculation by closing the RWST to RHR suction valves, valves RHR-8700A and RHR-8700B, and opening the containment recirculation sump suction valves, SI-8982A and SI-8982B. The ECCS system design includes an interlock, tested during procedure PEP V-7B, to ensure that operators can only open containment sump suction valves if the respective RWST suction valve is closed.

During performance of procedure PEP V-7B, Step 12.14.2, valve SI-2-8982B, RHR pump 2-2 suction from the containment recirculation sump, failed to open from the main control room. Licensee troubleshooting determined that external limit switch, POS-648, for valve RHR-2-8700B, RHR pump 2-2 suction from the RWST, was in a failed position. The failure of this limit switch, caused by a sheared internal roll pin, prevented the open permissive signal for valve SI-2-8982B. Since limit switch POS-648 failed during a planned refueling outage with Diablo Canyon Unit 2 shutdown, no technical specification entries were necessary. The licensee replaced limit switch POS-648 under Work Order 60090383 on May 18, 2016, prior to exiting the planned refueling outage. The licensee entered this issue into their corrective action program as Notification 50852345.

The inspectors reviewed the work history for valve RHR-2-8700B and limit switch POS-648. During refueling outage 2R17 completed on February 21, 2013, the licensee implemented Work Order 64014195 to replace the Limitorque actuator stem nut for valve RHR-2-8700B and completed maintenance procedure E-53.10R, “Augmented Stem Lubrication for Limitorque Operated Valves,” Revision 4. This maintenance included removal and replacement of limit switch POS-648 and its actuating lever. The inspectors noted that procedure MP E-53.10R included instructions for re-installing the stem mounted position switches and checks for proper operation. Specifically, procedure MP E-53.10R, Step 7.9.2(h), included instructions to “Check switches are properly operating by listening for an audible click from switch when valve is cycled OPEN and CLOSED.”

The inspectors noted that the licensee successfully tested POS-648 as part of post-maintenance testing for Work Order 64014195 and again on October 22, 2014, when procedure PEP V-7B was last performed. The licensee cycles valve RHR-2-8700B quarterly as part of the inservice testing (IST) program; however, the quarterly IST does not test the interlock provided by limit switch POS-648. As such, the inspectors concluded that POS-648 failed sometime between the last successful performance of surveillance procedure PEP V-7B on October 22, 2014, and the failure of valve SI-2-8982B to open on May 16, 2016.

Limit switch POS-648 is a Namco™ Model EA170 snap lock position switch, designed to snap over when actuated and includes a hard stop. The inspectors reviewed applicable maintenance, design, and testing instructions provided by the limit switch vendor. Within the publically available vendor documents, the inspectors identified the following precaution relative to the design, installation, and operation of Namco™ Snap-Lock Limit switches:

> Operating mechanisms for limit switches MUST BE so designed that, under any operating or emergency conditions, the limit switch is not operated beyond its overtravel limit position.

The vendor guidance also directed switch owners to the specific bulletin for the switch overtravel specifications. The inspectors reviewed the switch bulletin for Namco™ Model EA170-35100 snap lock limit switches, the same model used for POS-648. The inspectors noted that the switch specifications included a recommended travel of 7 degrees based on a required trip of 6.5 degrees, and a maximum overtravel of 36 degrees. The inspectors reviewed as-found photos of POS-648 following the May 16, 2016, failure and noted that the switch actuating arm position was at a nearly 45-degree angle relative to the normal position indicating that the position switch had exceeded the overtravel specification.

The inspectors determined that when POS-648 was re-installed following maintenance on February 21, 2013, the licensee did not set the switch and actuating arm correctly in accordance with the vendor recommendations to ensure that the overtravel specification was not exceeded. By operating the switch beyond the overtravel specification, valve force was applied to the limit switch lever and internal roll pin after reaching a hard stop. The repeated overloading of the lever roll pin eventually led to the failure of POS-648.

While the instructions in procedure MP E-53.10R, Step 7.9.2.(h), to check for proper operation by listening for an audible click, would verify the limit switch changed state, the inspectors determined this procedure step was inadequate to prevent overtravel of the externally mounted limit switch. Specifically, the inspectors determined that the procedure lacked specificity because it only ensured that the trip and reset of the switch occurs as the valve is exercised but did not provide adequate instructions to ensure the switch overtravel specification was not exceeded.

The inspectors interviewed licensee personnel responsible for determining the cause of the failure of POS-648. During that interview, the licensee shared conclusions regarding the cause of the failure of POS-648 that corresponded with the independent conclusions developed by the inspectors. In particular, the licensee determined that the maintenance instructions in procedure MP E-53.10R to listen for an audible click were insufficient to prevent over-ranging of the position switch lever. The licensee performed an extent-of-condition review of other motor operated valve (MOV) external limit switches that provide control or logic functions but would not provide an audible alarm or other indication if in a failed state. The licensee identified fifteen other limit switches that could be susceptible to the failure mechanism experienced on limit switch POS-648. The licensee walked down these switches on June 1, 2016, and identified no other similar switch installation problems. Notification 50852345 included corrective action CA 1, due March 20, 2017, to revise procedure MP E-53.10R to include detailed instructions for setting the travel of externally mounted limit switches.

<u>Analysis</u>. The inspectors determined the failure to establish adequate adjustment criteria for maintenance procedure MP E-53.10R was a performance deficiency. The performance deficiency is more than minor, and therefore a finding, because it is associated with the procedure quality attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, procedure MP E-53.10R, used by the licensee to perform limit switch adjustments on the Unit 2 valve RHR-2-8700B, did not provide adequate acceptance criteria to prevent overtravel of the actuating lever. This resulted in a subsequent failure of the limit switch, preventing the open permissive signal for valve SI-2-8982B, residual heat removal pump 2-2 suction from the containment recirculation sump, used during the ECCS recirculation mode. The inspectors evaluated the finding using the Attachment 0609.04, "Initial Characterization of Findings," worksheet to Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” issued June 19, 2012. The attachment instructs the inspectors to utilize

IMC 0609, Appendix A, “Significance Determination Process (SDP) for Findings At-Power,” issued June 19, 2012. In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” the inspectors determined that the finding required a detailed risk evaluation because it represented an actual loss of function of the train B ECCS for greater than its technical specification allowed outage time. A senior reactor analyst performed a detailed risk evaluation in accordance with IMC 0609, Appendix A, Section 6.0, “Detailed Risk Evaluation.”

Small and medium loss of coolant accident initiators with failures of the opposite train of ECCS or related support systems dominated the calculated increase in core damage frequency. The analyst did not evaluate the large early release frequency because this performance deficiency would not have challenged the containment. The NRC preliminarily determined that the increase in core damage frequency for internal and external initiators was 7.6E-06/year, in the low to moderate risk significance range (White). The results of the detailed risk evaluation are included in Attachment 2 of this report.

The inspector did not identify a cross-cutting aspect with this finding because it was not reflective of current performance. The inadequate procedure was developed in 2011 and did not reflect the licensee’s current performance related to procedure development.

<u>Enforcement</u>. Technical Specification 5.4.1.a, “Procedures,” requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Section 9.a of Appendix A of Regulatory Guide 1.33, Revision 2, requires in part, that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. On December 5, 2011, the licensee established procedure MP E-53.10R, “Augmented Stem Lubrication for Limitorque Operated Valves,” Revision 4, to perform maintenance on safety-related equipment including motor operated valves and their external limit switches. Contrary to the above, on December 5, 2011, the licensee failed to establish written procedures for performing maintenance on safety-related equipment which were appropriate to the circumstances. Specifically, the procedure only checked that motor operated valve external limit switches changed position during valve exercise but did not provide instructions to establish and check the travel of these switches within vendor established criteria. Consequently, the limit switch for valve RHR-2-8700B was installed such that it was operated repeatedly beyond overtravel tolerances resulting in its failure. The licensee entered this issue into their corrective action program as Notification 50852345 and initiated action to replace the failed limit switch. The licensee also initiated corrective actions to change maintenance procedure MP E-53.10R to ensure adequate acceptance criteria for limit switch travel were included, and performed an extent of condition for all other MOV stem mounted position switch interlocks circuits. As a consequence of this failed limit switch, the licensee was also in violation of Unit 2 Technical Specification 3.5.2, “ECCS – Operating,” because train B of the ECCS was determined to be inoperable for greater than the technical specification allowed outage time of 14 days, and the licensee failed to take actions required of the limiting condition of operation. Because this finding has been preliminarily determined to be of greater than very low safety significance (i.e., greater than Green), it is being characterized as

an apparent violation. AV 05000323/2016010-01, “Failure to Establish Adequate Work Instructions for Installation of Namco™ Snap Lock Limit Switches”

4OA6 Meetings, Including Exit

Exit Meeting Summary

On September 13, 2016, the inspectors presented the inspection results to Mr. E. Halpin, Senior Vice President and Chief Nuclear Officer, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Baldwin, Director, Nuclear Site Services
D. Evans, Director, Security & Emergency Services
L. Fusco, Manager, Mechanical Engineering
P. Gerfen, Station Director
M. Ginn, Manager, Emergency Planning
E. Halpin, Sr. Vice President, Chief Nuclear Officer Generation
H. Hamzehee, Manager, Regulatory Services
A. Heffner, NRC Interface, Regulatory Services
L. Hopson, Director Maintenance Services
T. Irving, Manager, Radiation Protection
K. Johnston, Director of Operations
M. McCoy, NRC Interface, Regulatory Services
J. Morris, Supervisor, Nuclear Regulatory Services
C. Murry, Director Nuclear Work Management
J. Nimick, Senior Director Nuclear Services
P. Nugent, Director, Quality Verification
A. Peck, Director, Nuclear Engineering
A. Warwick, Supervisor, Emergency Planning
J. Welsch, Site Vice President
R. West, Manager, System Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000323/2016010-01	AV	Failure to Establish Adequate Work Instructions for Installation of Namco™ Snap Lock Limit Switches (Section 4OA2)

Section 4OA2: Problem Identification and Resolution

Procedures

Number	Title	Revision
PEP V-7B	Test of ECCS Valve Interlocks	8
MP E-53.10R	Augmented Stem Lubrication For Limitorque Operated Valves	4-7
OP O-22	Emergency Operation of Motor Operated Valves	6
E-0	Reactor Trip or Safety Injection	35
EOP E-1.3	Transfer to Cold Leg Recirculation	22

MP E-53.10A1	Low Impact External Inspections of Limitorque Motor Operators	1

Notifications

50852066	50852180	50852345	50861001

Drawings

Number	Title	Revision
441239	Unit 2, Single Line Meter and Relay Diagram 480V System Bus Section 2H	48
441310	Unit 2, Schematic Diagram Residual Heat Removal Motor Operated Valves	31
441317	Unit 2, Schematic Diagram Safety Injection System Motor Operated Valves	19
500628	Unit 2, Electrical Diagram of connections, Elevation 115-140 foot, Area H	26
507610	Unit 2, Arrangement of Electrical Equipment at Elevation 100’, Area H	16

Work Orders

64014195

Miscellaneous

Number	Title	Revision
Calculation SDP16-02	SI-2-8982B Failure to Open During PEP V-7B in 2R19 due to Damaged Closed Position Switch for 8700B	0

Significance Determination

Significance Determination Basis:

(a) Screening Logic

Minor Question: In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the finding was determined to be more than minor because it was associated with the procedure quality attribute of the Mitigating Systems Cornerstone, and affected the associated cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency associated with the inadequate maintenance procedure resulted in inadequate criteria to ensure limit switch adjustments did not result in overtravel of the actuating lever for valve RHR-2-8700B. This resulted in a subsequent failure of limit switch POS-648, affecting the availability of the ECCS because this limit switch provides the open permissive signal for valve SI-2-8982B, the containment sump suction for the RHR system.

Initial Characterization: Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," the inspectors determined that the finding could be evaluated using the significance determination process. In accordance with Table 3, "SDP Appendix Router," the inspectors determined that the subject finding should be processed through Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012.

Issue Screening: In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," the inspectors determined that the finding required a detailed risk evaluation because it represented an actual loss of function of the Unit 2 train B ECCS for greater than its technical specification allowed outage time (i.e., 14 days). A senior reactor analyst performed a detailed risk evaluation in accordance with IMC 0609, Appendix A, Section 6.0, "Detailed Risk Evaluation."

Results: The detailed risk evaluation result is an increase in core damage frequency from the performance deficiency of 7.6E-6/year, characterizing the significance of the finding to be of low to moderate safety significance. This estimate used best available information and estimated the increase in core damage frequency to be 7.1E-6/year from internal events and 5.4E-7/year from external events.

(b) Detailed Risk Evaluation:

(1) Assumptions

Exposure time. The exposure time was 286 days. The licensee last successfully tested valve SI-2-8982B and the interlock associated with POS-648 on October 22, 2014. Valve SI-2-8982B failed to open 572 days later on May 16, 2016. Since the inception of the failure of the limit switch after the last operation could not be determined, the analyst used a "t/2" approached and assumed the exposure time to be half of 572 days, or 286 days. Repair time was not added because the deficiency was discovered and returned to a functional status during an outage when the valve was not needed.

Recovery. Overall recovery was assumed to have a failure probability of 2.4E-1 for small break LOCAs and smaller medium break LOCAs (MLOCAs); 3.4E-2 for seal LOCAs; and 1.0 for larger MLOCAs. Two methods of recovery were available – (1) local manual valve operation, and (2) electrical bypassing of the interlock through manual contactor operation. The derivation of these recoveries is covered in the “Internal Events” section of this evaluation.

Common cause. The increased potential for common cause failure of Valve SI-2-8982A, the same valve on the redundant train, was considered applicable. The analyst was unaware of any programmatic licensee action to defend against common cause failure; therefore, the analyst set the failure of valve SI-2-8982B to “TRUE” in the SPAR model. This increased the probability of common cause failure of Valve SI-2-8982A from 3.6E-5 to 3.8E-2.

The analyst also considered the remaining valves installed on Units 1 and 2 with externally mounted limit switches that receive the same maintenance as the valve that is the subject of the performance deficiency. For Unit 1, the analyst determined that the issue would be of very low safety significance since there was not an actual failure of a component.

For Unit 2, the remaining valves would not result in a significant increase in risk because the external limit switches are either 1) only associated with an annunciator function, 2) only associated with an equipment interlock function that is not used in an accident scenario or, 3) only associated with an equipment interlock function needed for long-term containment pressure control.

Operating history. The analyst assumed the plant operated at power or at shutdown conditions above those that necessitated operation of the RHR system for decay heat removal during the entire exposure time. This allowed the analyst to use the at-power SPAR model for the entire exposure time.

(2) Internal Events

Background / Introduction. The results of the probabilistic risk assessment (PRA) tool showed that the performance deficiency affected two initiators – small break loss of coolant accidents (SLOCA) and MLOCA. These events are characterized by reactor coolant leaking from the reactor coolant system, which would act to lower inventory and pressure of the reactor coolant system. In response to the loss of coolant and system pressure, a safety injection actuation signal actuates to start ECCS pumps. These pumps include both RHR pumps, both safety injection pumps, and both charging pumps. These pumps take suction from the refueling water storage tank, pump water into the reactor coolant system, which in turn leaks out of the break and into the containment where it collects in the containment recirculation sump. When the refueling water storage tank level reaches 33 percent level, operators secure the RHR pumps and perform valve manipulations to swap the suction of the emergency core cooling pumps from the refueling water storage tank to the containment recirculation sump. Valve SI-2-8982B is the first valve in the flowpath leading from the containment sump. The inability to open valve SI-2-8982B renders train B of core cooling inoperable during the recirculation phase of LOCAs. The licensee would have options to recover and open the valve, which are discussed in this evaluation. The licensee would also have the redundant train A flowpath available to successfully cool the reactor core if valve SI-2-8982B were unrecoverable. PRA demonstrates that the dominant core damage sequences involve failures of the train A flowpath and the inability to recover valve SI-2-8982B.

<u>Small Break Loss of Coolant Accidents</u>

For the purposes of this evaluation, SLOCA include pipe breaks up to 2 inches, catastrophic reactor coolant pump seal failures (seal LOCAs), and seal LOCA's caused by losses of cooling to the reactor coolant pump seals (brought about by loss of power to cooling for the seals).

SLOCA comprises 26.0 percent of the increase in core damage frequency. The results are driven by the failure of valve SI-2-8982B, failures of train A flowpath for recirculation sump flow, and the ability or inability to operate valve SI-2-8982B by alternative means.

The primary contributor of failures of the train A flowpath is attributed to an increased probability of common cause failure of its sump valve SI-2-8982A. Because valve SI-2-8982B failed and valve SI-2-8982A is subject to the same environment, maintenance, testing, etc., valve SI-2-8982A is exposed to an increased probability of failure. The common cause failure of SI-2-8982A comprises approximately two-thirds of the increase in core damage frequency from SLOCAs. The remainder of the increase in core damage frequency comes from power failures to components in the train A flowpath, valve failures in the flowpath, and pumps failures in the flowpath.

Recovery of valve SI-2-8982B through alternative means is also a contributor. These alternative means include either electrical operation by use of the motor contactors or manually by accessing the valve and operating the handwheel on the valve.

<u>Recovery of Valve SI-2-8982B</u>

Recovery actions to open valve SI-2-8982B are available by two alternate means, either electrically by use of the motor contactors, or manually by accessing the valve and operating the handwheel on the valve. In developing their assessment of the success probability of recovering valve SI-2-8982B, the licensee interviewed operators who indicated that both recoveries would be pursued in parallel.

1. <u>Electrical operation of Valve SI-2-8982A by use of motor contactors</u>. This recovery option takes advantage of the ability to bypass the interlock circuitry, which is the subject of the performance deficiency, preventing valve SI-2-8982B from opening. Manual operation of the electrical contactors provided line power directly to the motor operator for valve SI-2-8982B. Operation of the electrical contactors could be successful if properly performed, but inspectors found several impediments to absolute success.

The first potential impediment was the adequacy of procedural guidance used for the electrical operation recovery option. The direction to pursue recovery paths to open valve SI-2-8982B is contained in Emergency Operating Procedure (EOP) Emergency Contingency Action (ECA) 1.1, “Loss of Emergency Coolant Recirculation,” Revision 21. Step 2 of ECA 1.1 instructs operators to restore emergency coolant recirculation equipment by several means. Step 2.d has operators check power available to valves required for recirculation swap over and refer to an appendix with valve power supplies. The performance deficiency would not result in a loss of the valve’s main power supply. Instead, the performance deficiency would result in the main-line contacts being held open by the control circuit for valve SI-2-8982B. The analyst considered this an impediment to recovery because the procedure did not explicitly call out actions for a loss of control power to the motor operator. The analyst concluded from the licensee’s analysis that operator experience would guide them to use Step 2.d as the best fit for troubleshooting and take the step’s “response not obtained” action to locally operate the valves as required. The analyst judged that local operations are at the location of the valve, not in the electrical cabinet located away from the valve, and that this action to locally operate the valve did not specifically address use of the electrical contactors. Again, the analyst determined, based on interviews and discussions with the licensee, that operator experience and training could employ this as an option even though it is not explicitly called for in the emergency procedure.

The licensee established procedure O-22, “Emergency Operation of Motor Operated Valves,” Revision 6 to operate motor operated valves through use of the motor contactor. Procedure O-22 requires phone communication between the control board operator in the control room and the operator in the field at the cabinet when operating the valve. Inspectors toured the licensee’s training facilities used to instruct operators on how to locally operate contactors. The inspectors noted that the electrical cabinet used to train operators used a Telemecanique brand contactor, different from the Westinghouse Cutler Hammer brand contactors installed in the cabinet for valve SI-2-8982B. The different contactors have different operating methods. To operate the Telemecanique contactors, operators insert non-conducting rods above and below the contactor of interest. To operate the Westinghouse contactors, operators depress a gray plastic armature position indicator.

The analyst concluded that the difference in layout and methods of operating contactors between the training electrical cabinet and the plant electrical cabinet would present challenges to successful operation of the contactor. Also, during a walkdown with the licensee electricians, the inspectors noted that the electrical cabinet for valve SI-2-8982B housed both the open and close contactors. However, these contactors are not labelled such that an operator could tell which contactor was the open contactor.

The inspectors noted that Procedure O-22, Attachment 2, provided a typical cabinet layout for motor-operated valves in the plant. This diagram showed the open contactor located above the close contactor. During the walkdown, the inspectors asked electrical personnel if the orientation illustrated in Procedure O-22, Attachment 2, was the same orientation for the cabinet for valve SI-2-8982B. After approximately 6 minutes of inspecting the cabinet with the electrical schematic diagram, the three electrical personnel determined that the orientation was opposite of that illustrated in Procedure O-22, because the close contactor was located above the open contactor. The analyst considered these aspects to be additional impediments to successful operation of the valve.

The inspectors noted that prior to Step 6.11, the step instructing operators to locate the appropriate contactor, Procedure O-22 included a boxed “Note” that read, “…Those contactors that can’t be clearly identified may require assistance from engineering or maintenance for positive identification.”

The analyst concluded that Procedure O-22, Attachment 2 that provided a typical cabinet layout for motor operated valves, created a likelihood that some operators would consider the valve SI-2-8982B contactor orientation typical and not heed this note. The analyst also considered that to follow the note, additional time is required to have an engineer or electrician report to the cabinet, obtain the proper electrical print, and trace the cabinet wiring to ascertain which contactor was the open contactor and which contactor was the close contactor. This additional time affects the time available to open the valve using the electrical contractor and adversely influences the success rate of this action. The analyst also noted that operation of the contactors would require a screwdriver to defeat the door latch breaker trip and the operator would have to be dressed in an arc flash suit which the operator would have to obtain prior to this action.

The consequences of operating the incorrect contactor are potentially severe. If the licensee personnel operated the close contactor thinking they were opening the valve, the valve motor would drive the valve in the close direction with all of the motor-operated valve protective features bypassed. Because the valve is already closed, the motor would be in a stall condition and motor current would be at or near locked rotor amperage. The potential consequences of this mis-operation could include motor damage or burnout.

The analyst included these factors in the human reliability analyses performed using the SPAR-H method.

With the two methods performed in parallel (i.e., electrical contactors and manual valve manipulation methods), the inspectors concluded that the electrical contactor method would be ready for attempted use first. The assumed timing was:

Action	**Time (minutes)**	**Total time (hh:mm)**
Briefing the operation	15	00:15
Gather tools, dress out in arc flash suit, report to breaker, open cabinet	20	00:35
Recognize no labelling, summons electrician to cabinet	10	00:45
Obtain electrical print	10	00:55

Operate contactor (valve)	5	01:00

When added to the 10 minutes assumed to attempt swap over to recirculation and 30 minutes assumed to troubleshoot the issue, diagnose indications, and decide on a course of action, the analyst estimated a total time to success of approximately 1 hour and 40 minutes.

The analyst used these points to obtain the following human reliability analysis:

Electrical Recovery – Diagnosis (=1E-2)			
Time Available	Extra	0.1	The 1:40 hour time to diagnose and perform gives extra time when compared to the licensee's estimate of 2:35 hour to deplete the RWST (applying both diagnosis and action). The time from a depleted RWST until occurrence of core damage was also considered.
Stress	High	2	The level of stress would be higher than the nominal level due to unexpected alarms being present and consequences that could threaten plant safety.
Complexity	Nominal	1	No event information is available to warrant a change in this diagnosis performance shaping factor (PSF) from Nominal.
Experience/Training	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Procedures	Incomplete	20	Task instructions are absent to guide the operator to the appropriate electrical contactor operation
Ergonomics	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Fitness For Duty	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Work Processes	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Result = 4E-2 = 0.1 x 2 x 1 x 1 x 20 x 1 x 1 x 1 x 1E-2			

Electrical Recovery – Action (=1E-3)			
Time Available	Extra	0.1	The 1:40 hour time to diagnose and perform gives extra time when compared to the licensee's estimate of 2:35 hour to deplete the RWST (applying both diagnosis and action). The time from a depleted RWST until occurrence of core damage was also considered.
Stress	High	2	The level of stress would be higher than the nominal level due to unexpected alarms being present and consequences that could threaten plant safety.
Complexity	Highly	5	The evolution involved equipment line-up that involved defeated interlocks on valves, a highly complex task.
Experience/Training	Low	3	Different contactors were present in the cabinet than were trained on during operator training.
Procedures	Incomplete	20	The procedure provided operators with a generic orientation of the contactors which did not match the in-plant configuration. The note for operators to seek assistance is not explicit, stating that the situation ".. may require assistance.."
Ergonomics	Poor	10	The contactors in the panel are not labelled causing poor human-machine interface.
Fitness For Duty	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Work Processes	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
PSF = 0.1 x 2 x 5 x 3 x 20 x 10 x 1 x 1 = 600 Result = 3.8E-1 = 1E-3 x 600 / [1E-3 x (600 – 1)] + 1			

Combining diagnosis and action (4.0E-2 + 3.8E-1) yielded a failure probability of 4.2E-1.

2. <u>Manual operation of Valve SI-2-8982A by handwheel</u>. This recovery action involves operators utilizing the handwheel to open valve SI-2-8982B. The analyst considered the diagnosis to employ this option to be similar to the decision for electrical contactor operation, except Procedure ECA 1.1 was appropriate in directing local manual valve operations. Also the analyst concluded the assumption of 10 minutes to attempt swap over to recirculation and 30 minutes to troubleshoot the issue, diagnose indications, and decide on a

course of action that was appropriate for diagnosis of this action. The inspectors considered that the local manual valve operation path would present operators with the decision to incur more dose, face uncertain environmental and radiological factors at the valve, the potential to introduce a containment bypass flowpath, and the manual handwheel option requires more time than the electrical contactor option. In their analysis, the licensee considered this local manual valve operation as the sole credited recovery option. However, for the previously stated reasons, the analyst concluded this option would be employed after the electrical contactor option.

The inspectors noted several attributes of this action made it more complex. The valve is located adjacent to the containment in a special chamber. The chamber has an enclosed environment that may become radioactively contaminated following a LOCA. The licensee would need to implement actions to sample the environment for suitable breathing to prevent a radioactive intake. Alternatively, an operator would have to don protective clothing to prevent contaminating himself, don a respirator, climb a ladder to enter the chamber, and operate the valve. Any leakage from this valve (e.g., packing leakage) could serve to pressurize this chamber and require additional protective clothing to prevent contamination. To access the valve inside of the chamber, the licensee needs to remove 32 nuts, which act to secure the chamber. This additional time affects the time available to open the valve and adversely influences the success rate of this action.

The licensee estimated 90 minutes would be required to brief personnel, gather tools, and open the manway. Next the licensee estimated 10 minutes to open the valve. The analyst noted that according to licensee information, the valve would take 468 turns of the handwheel to open the valve. Factoring in fatigue from repetitive motion along with potentially cumbersome clothing in a hot environment, 25 minutes (or one turn approximately every 3 seconds) would be required. This makes the timeline as follows for execution:

Action	**Time (minutes)**	**Total time (hh:mm)**
Briefing the operation, gather tools, and open manway	90	01:30
Operate valve	25	01:55

When added to the 10 minutes assumed to attempt swap over to recirculation and 30 minutes assumed to troubleshoot the issue, diagnose indications, and decide on a course of action, the total time to success was estimated to be approximately 2 hours and 35 minutes (2.6 hours).

The analyst used these points to obtain the following human reliability analysis:

Mechanical Recovery – Diagnosis (=1E-2)			
Time Available	Nominal	1	The 2:35 hour time to diagnose and perform gives nominal time when compared to the licensee's estimate of 2:35 hour to deplete the RWST (applying both diagnosis and action). Combined with the time from a depleted RWST until occurrence of core damage.
Stress	High	2	The level of stress would be higher than the nominal level due to unexpected alarms being present and consequences that could threaten plant safety.
Complexity	Moderate	2	Several variables are involved in diagnoses including the knowledge of introducing a potential containment bypass path.
Experience/Training	Nominal	1	Adequate amount of instruction to perform.
Procedures	Nominal	1	Evaluated not to be a performance driver.
Ergonomics	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Fitness For Duty	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Work Processes	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Result = 4.0E-2 = 1 x 2 x 2 x 1 x 1 x 1 x 1			

Mechanical Recovery – Action (=1E-3)			
Time Available	Nominal	1	The 2:35 hour time to diagnose and perform gives nominal time when compared to the licensee's estimate of 2:35 hour to deplete the RWST (applying both diagnosis and action). Combine with the time from a depleted RWST until occurrence of core damage.
Stress	High	2	The level of stress would be higher than the nominal level due to unexpected alarms being present and consequences that could threaten plant safety.

Mechanical Recovery – Action (=1E-3)			
Complexity	Nominal	1	Little ambiguity existed in what needs to be performed
Experience/Training	Low	3	The licensee was unable to provide prior examples where the valve was operated manually by operators. Operators are not trained on manual valve operations inside the chamber.
Procedures	Incomplete	20	References for task instructions for opening the chamber are absent. Operators would have to refer to an outage procedure for guidance on opening the chamber.
Ergonomics	Poor	10	Poor human-machine interface is present. Access to the valve chamber requires a ladder. In chamber, the operator would be manipulating the valve, possibly in a respirator and wearing protective clothing. Operation of the valve would be in a hot environment, with awkward and tight clearances relative to the chamber walls.
Fitness For Duty	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
Work Processes	Nominal	1	No event information is available to warrant a change in this diagnosis PSF from Nominal.
PSF = 1 x 2 x 1 x 3 x 20 x 10 x 1 x 1 = 1200 Result = 5.4E-1 = 1E-3 x 1200 / [1E-3 x (1200 – 1)] + 1			

Combining diagnosis and action (4.0E-2 + 5.4E-1) yielded a failure probability of 5.8E-1.

Net effect. The analyst assumed the licensee would always have and attempt the electrical contactor option first. The SPAR-H analysis yielded a result that 58 percent (failure rate = 4.2E-1) of the time the licensee would successfully open the valve via the electrical contactor method. The analyst then assumed that failure to select the correct contactor to operate the valve would result in damage to the valve's electric motor, requiring the licensee to utilize the mechanical recovery option with the failure rate derived by SPAR-H (5.8E-1) for manual valve operations. This yielded an effective failure rate of 2.4E-1, calculated as follows:

$$p_{eff} = p_e \times p_m$$

p_{eff} = the effective human performance failure rate for both recoveries
p_e = the failure rate by electrical contactor operation
p_m = the failure rate by local manual valve operation

Catastrophic Seal LOCA. The results of this group is similar to the SLOCA group. The analyst combined the template events ZT-RCS-MDP-LK-BP1, "Reactor Coolant Pump Seal Stage 1 Integrity Fails (Binding/Popping Open)," and ZT-RCS-MDP-LK-BP2, "Reactor Coolant Pump Seal Stage 2 Integrity Fails (Binding/Popping Open)," in the SPAR model to develop an initiating event frequency for a catastrophic seal failure event of 2.5E-3/year. The analyst obtained this failure probability from WCAP-15603, "Westinghouse Owners Group 2000 Reactor Coolant Pump Seal Leakage for Westinghouse Pressurized Water Reactors." This value matches the initiating event frequency used by the licensee in their model within 2 percent. The analyst then applied the conditional core damage probability from a SLOCA to this initiating event frequency to estimate the change in core damage frequency resulting from a catastrophic seal failure with the performance deficiency present. The analyst considered that the low leakage rate from a failed reactor coolant pump seal would provide extra time for recovery via the electrical contactor and via the mechanical operation paths. This changed the effective recovery from this initiator to 3.4E-2.

Induced Seal LOCA. These reactor coolant leaks result from a loss of cooling to the reactor coolant pump seals. The dominant initiating events in SPAR which lead to induced seal failure are grid related losses of offsite power (LOOP), switchyard centered LOOPs, and transients. These events represent the smallest contribution to increase in core damage frequency. The analyst assumed a recovery of 3.4E-2, similar to the recovery of a catastrophic seal LOCA.

Medium Break Loss of Coolant Accidents

In NRC probabilistic risk assessment analyses, MLOCAs are breaks from 2 to 6 inches in size. MLOCAs may or may not increase pressure high enough to actuate the containment spray actuation signal, which occurs when pressure in the containment building reaches approximately 22 psig. This actuation signal would start the two containment spray pumps that combine to pump around 5000 gallons per minute from the RWST to the containment. This additional draw of water from the RWST would lower the available time for operators to take action to open valve SI-2-8982B by the alternative means and therefore adversely influence the success rate of these actions. The analyst reviewed Diablo Canyon PRA Calculation MAAP13-03, "Diablo Canyon Power Plant MAAP Success Criteria – Loss of Coolant Accident Definitions," Revision 0, to determine at which break size would actuate the containment spray actuation signal and start the containment spray pumps. In this calculation, a 2.9-inch break produced an 18 pound per square inch pressure in the containment. The analyst estimated that breaks above 3.5 inches would produce pressure in the containment sufficient to start the containment spray pumps.

From this estimate, the analyst broke MLOCAs into two classes. The first class consisted of breaks between 2 and 3.5 inches in size, not sufficient to start the containment spray pumps. Based on this 1.5-inch range, the analyst estimated simplistically that 37.5 percent of the MLOCAs would not cause starting of the containment spray pumps. Conversely, 62.5 percent of MLOCAs were assumed to start containment spray pumps. Once started, the analyst assumed that operators would leave the containment spray pumps running as required by the emergency operating procedures.

The analyst split the initiating event frequency by this 37.5 - 62.5 percent split and applied different recovery actions based on the differing times available. For the 37.5 percent of MLOCAs which would not start the containment spray pumps, recovery was similar to SLOCAs.

For the 62.5 percent that would actuate containment spray pumps, the analyst assumed that the RWST would deplete quickly and not allow sufficient time for recovery. Licensee estimates were that operators would only have around 30 minutes between RWST level of 33 percent and 4 percent. The 33 percent level is the point where operators would be required to attempt to swap from injection from the RWST to the containment recirculation sump. The 4 percent level is the level at which procedures instruct operators to secure all emergency core cooling pumps, thereby terminating any injection. That difference of 29 percent (33 – 4) would be depleted by the containment spray pumps in approximately 30 minutes. Actions to operate the motor contactors or locally manually operate the valve were far in excess of this timing, so the analyst considered that recovery was not possible.

Summary of Internal Events

The table below summarizes the dominant initiators and their contribution to the increase in core damage frequency. The overall results were an increase in core damage frequency of 8.2E-6/year from internal events:

Contributor	Increase in Core Damage Frequency
SLOCA	2.0E-6
Catastrophic Seal LOCA	1.4E-7
Induced Seal LOCA	1.1E-9
Smaller MLOCA	3.8E-8
Larger MLOCA	4.8E-6
Total	7.1E-6

(3) External Events

The analyst estimated the increase in core damage frequency from all external events to be 5.4E-7/year, using the individual estimates below.

Seismic. The analyst performed a seismic analysis using Revision 8.23 of the SPAR model. This analysis used a baseline conditional core damage probability representing a non-recoverable, switchyard-centered LOOP. The fragilities from Table AA-2 of Volume 2, External Events, of the Risk Assessment of Operational

Events Handbook were used. The increase in core damage frequency from seismic events was estimated to be 3.2E-7/year.

High winds. The analyst assumed no risk from high winds due to the historically low tornadic activity at Diablo Canyon.

Fire. The analyst used information from the licensee's fire probabilistic risk assessment model as the best available information to estimate the increase in core damage frequency from fires. The licensee received their safety evaluation for approval of application of NFPA 805 and is in transition to full compliance. The analyst applied the licensee's risk achievement worth value of 1.0452 to the baseline core damage frequency of 1.70E-5/year to estimate the increase in core damage frequency from fires to be 6.02E-7/year. Due to the low contribution relative to the internal events estimation of increase in core damage frequency, the analyst applied a generic recovery failure probability of 2.4E-1 derived from the SPAR-H for SLOCAs and applied it to all fires. This resulted in an increase in core damage frequency from fires of 2.2E-7/year.

(4) Large Early Release Frequency

The analyst reviewed the dominant sequences and compared them to Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process." The analyst performed a LERF screening to assess whether any of the core damage sequences affected by the finding were potential LERF contributors. The analyst determined that none of the sequences were significant LERF contributors and the increase in LERF was considered to be negligible.

(5) Uncertainties

Analytical

The analyst reviewed the analysis uncertainty for the base case with no recovery credit for the limited use model with basic event HPI MOV CC 8982B set to TRUE. The analyst then extrapolated the results to estimate that approximately 75 percent of results from a Monte Carlo distribution resulted in an increase in core damage frequency between 1.0E-6/year and 1.0E-5/year or less.

Qualitative Considerations

Competing priorities. The detailed risk evaluation only considered the recovery activities for the failed valve SI-2-8982B. For the core damage sequences of interest, other plant equipment would malfunction and attempts would be made to recover them. For example, in a case where the pump on the opposite train of the recirculation path was not working, operators would be challenged with additional diagnosis of that problem as well as deciding which recirculation path was more easily recoverable. This additional diagnosis would divert plant resources from recovery of valve SI-2-8982B. These competing priorities for recovery add uncertainty to the detailed risk evaluation performed and would serve to make recovery more unlikely.

Anecdotal information from a simulated recovery attempt. When the inspectors walked through operation of the valve SI-2-8982B by use of the electrical contactors with one engineer and two electricians, these individuals initially indicated that they would operate the contactors as represented in Procedure O-22. This operation would act to further close the valve, potentially causing irreparable damage. When the inspectors pointed this out, the individuals traced the wiring with the electrical drawing and corrected their response on the proper contactor they would operate. This was done by electrical personnel in a training environment. The uncertainty in how electrical personnel, if summoned to assist, would respond was only considered as success in the analyses. This information for recovery adds uncertainty to the detailed risk evaluation performed and would serve to make recovery more unlikely.

Temperature of the Recirculation Valve Chamber. The temperature of the recirculation valve chamber at the time operators would be required to enter and manipulate valve 8982B is unknown. If the temperature exceeded 130 degrees Fahrenheit, local manual valve operation could likely be impossible. This lack of information adds uncertainty and would serve to make recovery more unlikely.

(6) Sensitivities

The analyst performed sensitivities runs showing the results for various scenarios altering the influential assumptions:

- Different assumptions of recovery of the valve: The analyst adjusted the failure probability for various cases and compared them to the assumed failure probability in the table below:

Failure Probability of Recovery	**Comment**	**Increase in Internal Events CDF**
1.1E-2	98.9% success in recovery	5.0E-6/year
4.0E-2	96% success in recovery	5.3E-6/year
1.0E-1	90% success in recovery	6.0E-6/year
2.4E-1	76% success in recovery (assumed in analysis)	7.1E-6/year
5.0E-1	50% success in recovery	9.2E-6/year
No recovery	0% success in recovery	2.0E-5/year

- The potential for common cause failure of Train A Valve 8982A is not affected by the failure of Valve 8982B: The analyst estimated the increase of removing the cutsets which contained the common cause failure of valve 8982A. Result: Increase in CDF of 2.7E-6/year

- Consideration that valves 8982A and 8982B were tested in a staggered scheme: The analyst assumed the valves were tested nine months apart vice testing both during refueling outages. Result: Increase in CDF of 4.9E-6/year

- Use of the licensee's MLOCA frequency value combined with SPAR-H nominal recovery: The analyst used the licensee's lower initiating event frequency value of 2.3E-5/year along with the SPAR-H nominal recovery value of 1.1E-2. Result: Increase in CDF of 1.6E-6/year

(7) Licensee Results

The licensee provided the analyst with their analysis. The estimated increase in core damage frequency was 2.9E-5/year without recovery applied. This value did not adjust for common cause failure of the train A valve (valve SI-2-8982A). The analyst estimated that the SPAR model, when adjusted for catastrophic seal LOCAs and removal of consideration of elevated common cause failure of the train A valve, would estimate the increase in core damage frequency of 3.3E-5/year.

The licensee derived a failure probability for recovery with the local manual valve operation of 1.2E-2. When the licensee applied this recovery to their model, they estimated the increase in core damage frequency to be 7.5E-7/year. The analyst considered that the value of 1.2E-2 for recovery was conservative in light of the numerous adjustments needed to the performance shaping factors for less than nominal conditions affecting the recoveries. SPAR-H uses a nominal failure probability of 1.1E-2, which is near the licensee's recovery value. The analyst considered the application of SPAR-H to provide more realistic estimations of failure probabilities.

(8) Model Adjustments

Limited Use Model Version DCAN-RICK-2187 of the Diablo Canyon SPAR Model, was used with SAPHIRE Version 8.1.4. This version incorporated modifications to the model derived from the lessons learned from NUREG-2187, "Confirmatory Thermal-Hydraulic Analysis to Support Success Criteria in the Standardized Plant Analysis Risk Models – Byron Unit 1," Revision 0. The analyst used the default truncation of 1.0E-11.