REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEMS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2 The Digital Rod Position Indication System and the Demand Position Indication System shall be OPERABLE ~~and capable of determining the control rod positions within ± 12 steps~~. 13-01-LG

APPLICABILITY: MODES 1* and 2*. 13-08-LS20

ACTION:

a. With a maximum of one digital rod position indicator per ~~bank~~ group inoperable for one or more groups either: 13-02-LS15

1. Determine the position of the nonindicating rod(s) indirectly by the movable incore detectors at least once per 8 hours and ~~immediately~~ within 4 hours after any motion of the nonindicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, or 13-03-LS12

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours or be in Hot Standby within the next 6 hours. 13-04-M

b. With more than one digital rod position indicator per group inoperable either:

1 a) Determine the position of the nonindicating rods indirectly by the movable incore detectors at least once per 8 hours and within 4 hours after any motion of the nonindicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, and 13-08-LS20

(Q3.1-20)

1.b) Place the control rods under manual control immediately,
1.c) Monitor and record RCS Tavg at least once per hour, and

1 ~~b~~ d) Restore the digital rod position indicators to OPERABLE status within 24 hour such that a maximum of one digital rod position indicator per group in inoperable, or 13-08-LS20

2. Be in HOT STANDBY within the next 6 hours. 13-08-LS20

~~b~~ c. With a maximum of one demand position indicator per bank inoperable either:

1. Verify that all digital rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 12 steps of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours or be in Hot Standby within the next 6 hours. 13-04-M

SURVEILLANCE REQUIREMENTS

4.1.3.2 Each digital rod position indicator shall be determined to be OPERABLE by verifying that the Demand Position Indication System and the Digital Rod Position Indication System agree within 12 steps ~~at least once per 12 hours except during time intervals when the rod position deviation monitor is inoperable, then compare the Demand Position Indication System and the Digital Rod Position Indication System at least once per 4 hours~~ when exercised over the full range of rod travel once prior to criticality after each removal of the reactor head. 13-07-M 12-16-LG

* Separate condition entry is allowed for each inoperable rod position indicator and each demand position indicator per bank. 13-08-LS20

4.1.3.3 Insert

(Q3.1-21)

DESCRIPTION OF CHANGES TO TS SECTION 3/4.1
(Continued)

CHANGE NUMBER	NSHC	DESCRIPTION
13-06	A	Not applicable to DCPP. See Conversion Comparison Table. (Enclosure 3B)
13-07	M	The proposed modifications to the SR would require a verification of agreement between digital and demand indicator systems prior to criticality after each removal of the reactor vessel head, instead of every 12 hours. This reflects a reorganization of SRs in the ITS. The requirement for a 12 hour comparison would be moved to SR 3.1.4.1 in the ITS. The post-vessel head removal requirement would be a new specification that demonstrates rod position system OPERABILITY based on a comparison of indicating systems throughout the full range of rod travel. The Frequency requirement of prior to criticality after each removal of the reactor vessel head would permit this comparison to be performed only during plant outages that involve plant evolutions (vessel head removal) that could affect the OPERABILITY of the rod position indication systems. The Frequency change is based on Traveler TSTF-89.
13-08	LS20	Adds provision from Callaway's current specifications which would, under certain conditions, allow continued operation with more than one inoperable DRPI per group. A separate Condition entry allowance is permitted for each inoperable rod position indicator per group and each demand position indicator per bank. ~~A proposed Traveler TSTF-234 Westinghouse Owners Group (WOG) - 73, Rev. 1 is in processing to cover this issue.~~ Q3.1-20 ~~TR 3.1-006~~
13-09	LS23	Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B). Q3.1-21
14-01	R	~~The Shutdown Position Indication System Specification 3.1.3.3 is relocated outside of the TS. This is consistent with NUREG-1431.~~
15-01	R e	~~The Rod Drop Time Specification 3.1.3.4 is relocated outside of the TS. The RCS temperature limit and reactor coolant pumps operating requirement for rod drop testing are combined with CTS Surveillance 4.1.3.4, then incorporated into ITS SR 3.1.4.3. This is consistent with NUREG-1431.~~ → Not used Q3.1-22
15-02	A	~~The Rod Drop Time SR 4.1.3.4.a is moved to the Control Rod ITS LCO 3.1.4 as SR 3.1.4.3. This change is consistent with NUREG-1431.~~ Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B). Q3.1-22
16-01	LS14	This TS would be revised to apply to shutdown "banks" instead of shutdown "rods;" this is consistent with NUREG-1431. The current ACTION statement permits one rod to be inserted beyond the limits; the proposed ITS Condition A would allow one or more banks to be inserted beyond the limit.

TECH SPECH CHANGE		APPLICABILITY			
NUMBER	DESCRIPTION	DIABLO CANYON	COMANCHE PEAK	WOLF CREEK	CALLAWAY
13-04 M	A requirement would be added to bring the plant to MODE 3 within 6 hours if the required ACTIONS and Completion Times are not met.	Yes	Yes	Yes	Yes
13-05 A	The proposed change would retain an ACTION statement, currently in the plant TS, that permits continued POWER OPERATION with more than 1 digital rod position indicator per group inoperable.	No, not in CTS - see 13-08-LS20.	No, not in CTS - see 13-08-LS20.	Yes	Yes
13-06 A	The change would allow separate Condition entry for each inoperable DRPI per group or each demand indicator per bank.	No, not in CTS - see 13-08-LS20.	No, not in CTS - see 13-08-LS20.	Yes	Yes
13-07 M	The proposed modifications to the SR would verify agreement between digital and demand indicator systems prior to criticality after the reactor vessel head was removed instead of every 12 hours. The Frequency change is based on Traveler TSTF-89.	Yes	Yes	Yes	Yes
13-08 LS20	Adds provision in Callaway's current specifications which would, under certain Conditions, allow continued operation with more than one inoperable DRPI per group. ~~This is consistent with Traveler WOG-73, Rev. 1.~~ → ~~TSTF-234~~	Yes Q3.1-20	Yes TR3.1-006	No, already in CTS.	No, already in CTS.
13-09 LS23	CTS ACTIONS b.1.b) and b.1.c) of LCO 3.1.3.2 are deleted. SDM is ensured in MODES 1 and 2 by rod position. Multiple inoperable DRPIs will have no impact on SDM in MODES 1 and 2 if the control rod positions are verified by alternate means and rod motion is limited consistent with the accident analyses. Deletion of these requirements is consistent with traveler ~~WOG-73, Rev. 1~~. →	No, not in CTS. TSTF-234	No, not in CTS. TR3.1-006	Yes	Yes
14-01 R	Relocates CTS 3.1.3.3 to licensee controlled documents, consistent with NUREG-1431.	~~Yes, see LAR 95-07 dated 10/4/95, DCL 95-222.~~ → No, see Amendments 120/118.	Yes, relocated to TRM.	No, see Amendment 89.	No, see Amendment 103.

Q3.1-21

Industry Travelers Applicable to Section 3.1

TRAVELER #	STATUS	DIFFERENCE #	COMMENTS
TSTF-9, Rev. 1	Incorporated	3.1-1	NRC approved.
TSTF-12, Rev. 1	Incorporated	3.1-15	NRC approved. ITS Special Test Exception 3.1.10 is retained and re-numbered as 3.8.1, consistent with this traveler and TSTF-136.
TSTF-13, Rev. 1	Incorporated	3.1-4	NRC approved.
TSTF-14, Rev. ~~3~~ 4	Incorporated	3.1-13	NRC approved. TR 3.1-005
TSTF-15, Rev. 1	Incorporated	N/A	NRC approved.
TSTF-89	Incorporated	3.1-8	NRC approved.
TSTF-107, Rev. 1	Incorporated	3.1-6	Q3.1-15
TSTF-108, Rev. 1	~~Not~~ Incorporated	~~N/A~~ 3.1-21	~~Not~~ NRC approved ~~as of cut off date~~ TR 3.1-001
TSTF-110, Rev. ~~1~~ 2	Incorporated	3.1-10	NRC Approved TR 3.1-004
TSTF-136	Incorporated	3.1-9, 3.1-15	
TSTF-141	Not Incorporated	N/A	Disagree with change; traveler issued after cut-off date
TSTF-142	~~Not~~ Incorporated	~~N/A~~ 3.1-22	~~Traveler issued after cut off date~~. NRC Approved. TR 3.1-003
~~WOG-73, Rev. 1~~, TSTF 234	~~Incorporated~~	~~3.1-7~~	~~TR 3.1-006~~
WOG-105	Incorporated	3.1-16	Q3.1-20

3.1-9

3.1 REACTIVITY CONTROL SYSTEMS

~~3.1.8~~ 3.1.7 Rod Position Indication

LCO ~~3.1.8~~ 3.1.7 The Digital Rod Position Indication (DRPI) System and the Demand Position Indication System shall be OPERABLE. B-PS

APPLICABILITY: MODES 1 and 2.

ACTIONS

ED
~~3.1-7~~
Q3.1-20

---------------------------NOTE---------------------------
Separate Condition entry is allowed for each inoperable rod position indicator ~~per group~~ and each demand position indicator ~~per bank~~.

CONDITION	REQUIRED ACTION	COMPLETION TIME	
A. One ~~[D]~~RPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators indirectly by using movable incore detectors. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours	B-PS 3.1-12
B. More than one DRPI per group inoperable.	B.~~1~~ ③ Verify the position of the rods with inoperable position indicators indirectly by using movable incore detectors. AND B.~~2~~ ④ Restore inoperable position indicators to OPERABLE status such that a maximum of one DRPI per group is inoperable.	Once per 8 hours 24 hours	3.1-7 3.1-12
~~B~~ C. One or more rods with inoperable ~~position indicators~~ DRPIs have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	~~B~~C.1 Verify the position of the rods with inoperable position indicators indirectly by using movable incore detectors. OR ~~B~~C.2 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours 8 hours	3.1-17 B 3.1-12
	B.1 Place the control rods under manual control. AND B.2 Monitor and record reactor coolant system Tavg. AND	Immediately Once per 1 hour	3.1-7 Q3.1-20

ACTIONS
(continued)

A.1

When one DRPI per group fails, the position of the rod may still be determined indirectly by use of the movable incore detectors. The Required Action may also be ensuring at least once per hours that f_Q satisfies LCO 3.2.1, $F_{\Delta H}$ satisfies LCO 3.2.2, and SDM is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1 or C.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 3).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1 ~~and~~ B.2, B.3, and B.4

When more than one DRPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Together with The indirect position determination available via movable incore detectors this will minimize the potential for rod misalignment.

Insert

Q3.1-20

Placing the Rod Control System in manual assures unplanned rod motion will not occur.

Insert for revised FLOG Response Q3.1-20

ITS Section 3.1 - Enclosure 5B - page B3.1-30

The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition. Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

JUSTIFICATION FOR DIFFERENCES FROM NUREG-1431

NUREG-1431 Section 3/4.1

This Enclosure contains a brief discussion/justification for each marked-up technical change to NUREG-1431, to make them plant-specific or to incorporate generic changes resulting from the Industry/NRC generic change process. The change numbers are referenced directly from the NUREG-1431 mark-ups (Enclosure 5A). For Enclosures 3A, 3B, 4, 6A, and 6B text in brackets "[ ]" indicates the information is plant specific and is not common to all the JLS plants. Empty brackets indicate that other JLS plants may have plant specific information in that location.

CHANGE NUMBER	JUSTIFICATION
3.1-1	In accordance with TSTF-9, Rev. 1, this change would relocate the specified limit for SDM from ITS to the COLR. This change occurs in several specifications including the specification for SDM and those specifications with ACTIONS that require verifying SDM within limits.
3.1-2	Q3.1-4 ~~The Note for SR 3.1.2.1 indicates that predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 EFPD after each refueling. However, both the Bases for Specification 3.1.3 and the CTS requirements in Specification 3.1.1.5 state that the normalization shall be done prior to exceeding a fuel burnup of 60 EFPD after each refueling.~~ Not used.
3.1-3	~~Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).~~ Not Used
3.1-4	Q3.1-23 SR 3.1.4.2 of NUREG-1431, Rev. 1 would be deleted. In accordance with TSTF-13, Rev. 1, the intent of this SR is only to determine the next frequency for SR 3.1.4.3. TR3.1-006 Performance of SR 3.1.4.2 is not necessary to assure that the LCO is met; SR 3.1.4.3 fulfills that purpose. Therefore, SR 3.1.4.2 may be deleted. In addition, the note in the frequency column of SR 3.1.4.2 would be moved to become Note 1 in the surveillance column of SR 3.1.4.3. This is for clarification purposes. As discussed in CN 3.1-9, section renumbering results in SR 3.1.4.3 of NUREG-1431, Rev. 1 becoming ITS SR 3.1.3.2.
3.1-5	Per CTS [3.1.3.1], the words "with all" have been removed from ITS LCO 3.1.4. This is a clarification that ensures the proper interpretation of the LCO. The change makes it clear that only one channel of DRPI is necessary to meet the alignment accuracy requirement of the LCO. With the word "all" in the statement, it may be possible for those unfamiliar with the DRPI design to interpret the LCO as applying to all channels of DRPI.
3.1-6	LCO 3.1.4 would be split into two separate statements to clarify that the alignment limit is separate from OPERABILITY of the control rod. The Condition A wording is broadened from "untrippable" to "inoperable" to ensure the Condition encompasses all causes of inoperability. Previous wording was ambiguous for rods that, for instance, had slow drop times but were still trippable. These slow rods are inoperable rods, and the change clarifies the appropriate ACTIONS. The Bases are changed to reflect the changes to the LCO and Condition A. These changes are based on TSTF-107.
3.1-7	This change to the ISTS would incorporate, into LCO 3.1.7, an ACTION statement that was previously approved as part of the Callaway and Wolf Creek licensing basis ~~as revised in Enclosure 2~~. The ACTION statement would permit continued POWER OPERATION for up to 24 hours with more than one DRPI channel per rod group inoperable. Q3.1-20 The ACTION statement specifies additional Required ACTIONS beyond those applicable to the Condition of 1 DRPI channel per group inoperable. The Bases for this change also would be incorporated into the Bases for the plant ITS. ~~These changes are consistent with Traveler WOG-73, Rev. 1. The note under the ACTIONS is changed to be consistent with the new Required Actions.~~ TSTF-234 TR3.1-006

CONVERSION COMPARISON TABLE FOR DIFFERENCES FROM NUREG-1431, SECTION 3/4.1

TECHNICAL SPECIFICATION CHANGE		APPLICABILITY			
NUMBER	DESCRIPTION	DIABLO CANYON	COMANCHE PEAK	WOLF CREEK	CALLAWAY
3.1-1	In accordance with industry Traveler TSTF-9, Rev. 1,this change would relocate the specified limits for SDM from several TS to the COLR.	Yes	Yes	Yes	Yes
3.1-2	~~Changes the note to SR 3.1.2.1, which deals with verifying core reactivity within limits, to state that the normalization of predicted reactivity values to correspond to measured values shall be done prior to exceeding a fuel burnup of 60 EFPD after each refueling.~~ Not used	~~Yes~~ NA	~~Yes~~ NA	~~No, maintaining ITS wording.~~ NA	~~No, maintaining ITS wording.~~ NA Q3.1-4
3.1-3	~~The Wolf Creek ITS LCO 3.1.6 Required Action C.1 is revised from "Be in MODE 3." to "Be in MODE 2 with k_{eff} < 1.0."~~ Not used	~~No~~ NA	~~No~~ NA	~~Yes~~ NA	~~No~~ NA Q3.1-23
3.1-4	In accordance with industry Traveler TSTF-13, Rev. 1, SR 3.1.4.2, which requires verifying MTC within the 300 ppm boron limit, is deleted and the note in that SR is moved to the SR that requires the lower MTC limit to be verified. The deleted SR is not a requirement separate from the lower MTC verification SR, but is essentially a clarification of when the SR for the lower MTC limit should be performed.	Yes TR 3.1-006	Yes	Yes	Yes
3.1-5	Per CTS [3.1.3.1], the words "with all" are removed from the LCO for control rod alignment limits. This ensures that the number of channels of DRPI required to be OPERABLE will not be misconstrued.	Yes	Yes	Yes	Yes
3.1-6	In accordance with TSTF - 107, the change provides additional clarification that the alignment limits in the LCO are separate from the OPERABILITY of a control rod.	Yes	Yes	Yes	Yes
3.1-7	An ACTION statement that was previously approved as part of the current licensing basis of Callaway and Wolf Creek would be added to ITS 3.1.7 ~~as revised in Enclosure 2~~. The ACTION statement would permit operation for up to 24 hours with more than one digital rod position indicator per group inoperable.	Yes Q3.1-20	Yes	Yes	Yes

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: Q 3.2-3 **APPLICABILITY:** CA, WC, DC, CP

REQUEST: ITS 3.2.1 Heat Flux Hot Channel Factor
CTS 3/4.2.2 Heat Flux Hot Channel Factor (All FLOG Plants)
DOC 02-06-A
JFD 3.2-12
ITS SR 3.2.1.1 & 3.2.1.2 Frequency

Comment: The ITS SR frequency has been changed from the STS frequency of 12 hours to 24 hours. This is based upon the incorrect justification that the CTS would allow 24 hours based upon ITS SR 3.0.3, since the CTS does not specify a frequency. Adopt the STS SR frequency of 12 hours.

FLOG RESPONSE (original): The change descriptions (DOC 2-06-A & JFD 3.2-12) will be revised to provide a basis for the 24 hours that is predicated on the time required to perform the surveillance.

Callaway and Wolf Creek are incorporating this change (DOC 02-06-A, JFD 3.2-12) in lieu of maintaining CTS which did not specify any completion time. DOC 02-13-LG (applicable to Callaway only) and JFD 3.2-17 are no longer used.

FLOG RESPONSE (supplement): As discussed in a telecon with the NRC staff on October 1, 1998, additional justification for the basis of the 24 hour surveillance frequency has been added to JFD 3.2-12.

Additionally, this item is related to Comment Number Q 3.2-7 for Callaway and Wolf Creek. No additional response is required for Comment Number Q 3.2-7.

ATTACHED PAGES:

Attachment 8 - CTS 3/4.2 / ITS 3.2

Encl. 6A 2

JUSTIFICATION FOR DIFFERENCES FROM NUREG-1431

NUREG-1431 Section 3/4.2

3.2-08 Consistent with Traveler TSTF-99, the LCO 3.2.1 (F_Q Methodology), Required ACTION B.1. Completion Time for the reduction of the AFD limits if $F^W_Q(Z)$ is not within limits is increased from 2 hours to 4 hours. This makes it consistent with the Completion Time associated with Required ACTION A.2. of LCO 3.2.1 (F_{XY} methodology). The change is acceptable because it eliminates an inconsistency in the ITS.

3.2-09 For consistency with CTS 3.2.4 and ITS 3.3.1, Condition D, the breakpoints for the Applicability of the surveillances in the notes in ITS SR 3.2.4.1 and SR 3.2.4.2 are modified to be applicable at less than or equal to 75 percent RTP, and greater than 75 percent RTP, respectively. This is an administrative change that retains CTS requirements and is consistent with TSTF-241. Q3.2-6

3.2-10 Consistent with Traveler TSTF-110, this change moves requirements for increased surveillance frequencies in the event of inoperable alarms to licensee controlled documents. This change is acceptable because it removes requirements regarding alarms and alarm responses that are not necessary to be in the TS to protect public health and safety. Inserta Q3.2-3

3.2-11 Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).

3.2-12 ~~Consistent with CTS,~~ ~~the~~ T the required time for completion of a flux map for determination of the heat flux hot channel factor is changed from 12 hours to 24 hours after achieving equilibrium Conditions. The proposed change affects SR 3.2.1.1 and SR ~~3.2.2.1~~ 3.2.1.2. Based on plant experience, The proposed time (24 hours) is a reasonable time period for Insert ~~the completion of the surveillance and does not allow for plant operation in an uncertain condition for a protracted time period. This change is consistent with the TS requirements of Specification 3.0.4 (and associated Bases) that allow 24 hours for the completion of a surveillance after prerequisite plant conditions are attained and for which an exception to Specification 4.0.4 was provided.~~

3.2-13 This change retains the CTS for the performance of peaking factor determinations following plant shutdowns. The CTS, through the exemption to Specification 4.0.4, allows prerequisite plant conditions to be obtained prior to requiring that the surveillance be completed. Insert Q3.2-4

3.2-14 Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).

3.2-15 This change incorporates Traveler TSTF-109. ACTION A.2. would require the QPTR be determined rather than performing a specific surveillance because more than one surveillance can be used to determine QPTR. SR 3.2.4.1 was revised to retain allowance that SR 3.2.4.2 may be performed in lieu of SR 3.2.4.1. ~~The note for SR 3.2.4.2 is changed to require performance if one "or more" QPTR inputs are inoperable with RTP > 75 percent.~~ Q3.2-10 These changes are acceptable because they clarify the ITS regarding frequency and use of incore flux monitoring for QPTR measurement. The changes reflect that incore detectors provide an acceptable QPTR determination during all plant Conditions.

3.2-16 This change would require both transient and static F_Q measurements be determined when performed for Required ACTIONS 3.2.4 A.3 and A.6. The intent of the Required ACTIONS is to verify that $F_Q(Z)$ is within its limit. $F_Q(Z)$ is approximated by $F^C_Q(Z)$ (which is obtained via SR 3.2.1.1) and $F^W_Q(Z)$ (which is obtained via SR 3.2.1.2). Thus, both $F^C_Q(Z)$ and $F^W_Q(Z)$ must be established to verify $F_Q(Z)$. This change is consistent with Traveler WOG-105.

3.2-17 ~~Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).~~ Not used Q3.2-3

3.2-18 Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).

3.2-19 Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B).

The note and frequency for SR 3.2.4.2 are revised consistent with typical presentation formats that provide for a period of time after establishing conditions. Q3.2-10

3.2-20 Not applicable to DCPP. See Conversion Comparison Table (Enclosure 6B). Q 3.2-1

Insert for Supplemental FLOG Response Q3.2-3

ITS Section 3.2 - Enclosure 6A - page 2

Insert a for JFD 3.2-12:

A flux map is taken after a power level increase greater than a specified amount to verify F_Q is within limits and to provide assurance that F_Q will remain within limits until the next required flux map is taken. Based on plant experience, the flux maps taken during power ascension provide a high degree of confidence that F_Q will be within limits at the next power plateau. As such, the exact time period allowed for performance of the surveillance, after reaching equilibrium, is not a significant safety consideration. The proposed time (24 hours) is a reasonable time period for obtaining and evaluating a flux map and then completing the procedural steps associated with this surveillance. Further, the 24 hour time period provides a reasonable limit on the length of time that the plant can operate in an unconfirmed condition.

Enclosure 6a – page 2

INSERT for 3.2-12:

obtaining and evaluating a flux map and then completing the procedural steps associated with this surveillance. Further, the 24 hours time period does not allow for plant operation in an uncertain condition for a protracted time period.

Enclosure 2
PG&E Letter DCL-98-154

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: Q 3.4.13-5 **APPLICABILITY:** DC

REQUEST:

ITS Bases 3.4.13 LCO and Bases SR 3.4.13.1 (Diablo Canyon)

> **Comment**: The discussions include CRDM canopy welds as exceptions to the definition. That exception is not included in the Bases discussion for ITS 3.4.13 Actions B.1 and B.2 and the exception is not justified.

FLOG RESPONSE (original): LCO 3.4-13 is intended to identify "impending gross failure" (CTS Bases 3.4.6.1) where as leaking seals and gaskets are recognized as not being associated with impending gross failure. The CRDM canopy welds are specialty seals where the "strength is provided by a separate device" (ASME Section III, 1989, NB-4360). The function of this weld is to provide a seal against leakage, rather then provide reactor coolant pressure boundary integrity against gross failure. Leakage of a CRDM canopy seal weld is not indicative of impending gross failure of the pressure boundary. They should therefore be included as IDENTIFIED or UNIDENTIFIED LEAKAGE and not as PRESSURE BOUNDARY LEAKAGE.

FLOG RESPONSE (supplement): On October 8, 1998, the NRC requested supporting documentation that leakage of a CRDM canopy seal weld is not indicative of impending gross failure of the pressure boundary. Attached is documentation to support this position.

ATTACHED PAGES:

Supporting Documentation

PG&E Letter to NRC (DCL-89-060) dated March 10, 1989
Westinghouse letter to PG&E (PGE-88-622) dated June 14, 1988

114646

Westinghouse Electric Corporation
Power Systems

PGE-88-622

Nuclear Technology
Systems Division

Box 355
Pittsburgh Pennsylvania 15230 0355

001.3

June 14, 1988
NS-OPLS-OPL-II-88-394

Mr. J. D. Shiffer
Vice President, Nuclear Power Generation
Pacific Gas & Electric Company
77 Beale Street
San Francisco, CA 94106

Attention: T. L. Grebel

PACIFIC GAS AND ELECTRIC COMPANY
NUCLEAR PLANT, DIABLO CANYON SITE UNITS 1 AND 2
TECH SPEC INTERPRETATION - PRESSURE BOUNDARY LEAKAGE

Dear Mr. Shiffer:

This letter is in response to a request by your Ms. J. R. Hinds of the Diablo Canyon Regulatory Compliance group to formalize a Technical Specification interpretation made recently by Westinghouse. The purpose of the interpretation is to say that leakage observed from canopy seal welds on the CRDM penetrations need not be considered pressure boundary leakage as defined in the Diablo Canyon Technical Specifications. The basis for making this interpretation is that the canopy seal weld is a non-structural weld such that leakage from it would not be indicative of impending gross structural failure. The complete interpretation including a discussion of the bases is attached to this letter.

Note that this interpretation does not apply to CRDM canopy seal welds that have had leakage repaired by a weld overlay or multiple weld build-up process.

If you have any questions concerning the information in this letter please contact A. M. Sicari at (412) 374-5585 or the undersigned.

Very truly yours,

WESTINGHOUSE ELECTRIC CORPORATION

Michael J Miller / for
J. C. Hoebel, Manager
Pacific Gas and Electric Project

A. M. Sicari
Attachment: Interpretation of the Tech Spec definition of PRESSURE BOUNDARY LEAKAGE as it applies to CRDM canopy seal welds.

RECEIVED
JUN 22 1988
[illegible]

114646

Attachment to PGE-88-622

SUBJECT: Technical Specification Interpretation
Diablo Canyon Unit Nos. 1 & 2
Section 1, Definitions; Subsection 1.24,
PRESSURE BOUNDARY LEAKAGE

QUERY:

Is leakage from a CRDM penetration canopy seal weld to be construed as PRESSURE BOUNDARY LEAKAGE or as IDENTIFIED or UNIDENTIFIED LEAKAGE as these are defined in the Technical Specifications for the purposes of compliance with LCO 3.4.6.2, Reactor Coolant Leakage.

INTERPRETATION:

Leakage from a CRDM penetration canopy seal weld should be construed as either IDENTIFIED or UNIDENTIFIED LEAKAGE and not as PRESSURE BOUNDARY LEAKAGE for the purposes of compliance with LCO 3.4.6.2, Reactor Coolant Leakage. This is consistent with both the language and the intent of the subject Technical Specifications.

DISCUSSION:

The CRDM penetration canopy seal weld is not a structural weld and thus is not relied upon to for maintaining the structural integrity of the reactor coolant system. The CRDM is attached by means of a threaded joint which provides the mechanical means of holding the CRDM housing in place when the system is pressurized. Similarly, in the case of spare CRDM penetrations, a threaded plug is installed with the threaded joint providing the mechanical means of closing the reactor coolant system.

Section 1.24 of the Technical Specifications defines PRESSURE BOUNDARY LEAKAGE as leakage through a non-isolable fault in a Reactor Coolant System "component body, pipe wall, or vessel wall." The CRDM penetration canopy seal weld is clearly not covered by the language of this definition.

This interpretation is also consistent with the intent of the subject Technical Specification. Section 3/4.4.6.2, BASES for OPERATIONAL LEAKAGE, states that the reason for prohibiting PRESSURE BOUNDARY LEAKAGE of any magnitude is that such leakage may be indicative of an impending gross failure of the pressure boundary. The canopy seal weld provides a seal against any leakage which might otherwise occur through the threaded joints and leakage through canopy seal welds is in no way indicative of any impending gross failure of the reactor coolant pressure boundary.

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: Q 3.5.5-1 **APPLICABILITY:** DC, CP

REQUEST:

Section 3.4 DOC 6-21 LS 35
Section 3.5 JFD 3.5-4
CTS 3.4.5.2 Action b (CP)
CTS 3.4.6.2 Action b (DC)
ITS 3.5.5 Action A

This change is a change to both the CTS and the STS and is beyond the scope of the conversion review and is generic. DOC 6-21 states that this change is consistent with WOG-84.

Comment: Please provide the current status of WOG-84. If WOG-84 is not approved by the TSTF, then this change should be withdrawn from the conversion submittal at the time of the TSTF rejection. If WOG-84 has not been acted on by the TSTF, or is approved by the TSTF but not approved by the NRC by the time the draft safety evaluation is being prepared, then it should be withdrawn from the conversion submittal at that time. This change will not be reviewed on a plant-specific basis.

FLOG RESPONSE (original): DCPP and CPSES will continue to pursue the revisions proposed by this change. WOG-84 is now TSTF-236 which was approved by the TSTF on February 5, 1998. The NRC has requested that the WOG provide additional justification to support the extended Completion Time and changes to Required Action A. The WOG is preparing that information in addition to proposed changes to the 3.5.5 LCO and SRs. The revised traveler will be issued in the near future to the NRC.

FLOG RESPONSE (revised): Per discussions with the NRC, since TSTF-236 has not been approved, the extension in seal water injection flow AOT from 4 hours to 72 hours associated with the TSTF will be withdrawn.

ATTACHED PAGES:

Attachment 10 - CTS 3/4.4

Encl 2	3/4 4-19
Encl 3A	10
Encl 3B	9
Encl 4	Table of Contents, 62, 63

Attachment 11 - ITS 3.5

Encl 5A	Traveler Status sheet, 3.5-10
Encl 5B	B 3.5-37
Encl 6A	1
Encl 6B	1

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 1 gpm UNIDENTIFIED LEAKAGE.

150 gallons per day of primary-to-secondary leakage through any one steam generator,

DC 3.4-003

c. ~~1 gpm total reactor to secondary leakage through all steam generators and 500 gallons per day through any one steam generator.~~

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System.

~~e.~~ 40 gpm CONTROLLED LEAKAGE at a Reactor Coolant System pressure of 2235 ± 20 psig., and. 06-06-A

f. ~~1 gpm leakage at a Reactor Coolant System pressure of 2235 ±20 psig for Reactor Coolant System Pressure Isolation Valves as specified in Table 3.4-1.~~ Leakage from each Reactor Coolant System Pressure Isolation Valve shall be < 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig. 06-07-LG 06-25-LS26

DC 3.4-003

APPLICABILITY: MODES 1, 2, 3(*) and 4#(*). 06-08-LS9

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE, reactor coolant pump (RCP) seal injection flow, and leakage from Reactor Coolant System pressure isolation valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. 06-09-LS10

Q 3.5.5-1

(new) With RCP seal injection flow greater than the above limit, ~~verify >100% flow equivalent to a single OPERABLE ECCS charging train is available within 4 hours and~~ reduce the flow rate to within limits within ~~2~~ (4) hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours. ~~06-21-LS35~~ 06-09-LS10

DC 3.4-ED

c. With any Reactor Coolant System pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one ~~two~~ closed manual, ~~and/or~~ deactivated automatic, or check valve##, and within 72 hours by the use of a second series closed manual, deactivated automatic, or check valve ##; or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. (**) (###) 06-11-LS11 06-12-M 06-29-LS38

Q3.4.14-3 06-30-A

* For MODES 3 and 4, if steam generator water samples indicate less than the minimum detectable activity of 5.0 E-7 microcuries/ml for principal gamma emitters, the leakage requirement of specification 3.4.6.2c may be considered met.

DC-3.4-003

** Separate Action entry is allowed for each PIV flow path 06-29-LS38

Q3.4.14-3

Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV 06-30-A

DESCRIPTION OF CHANGES TO TS SECTION 3/4.4

Q3.5.5-1

CHANGE NUMBER	NSHC	DESCRIPTION
06-21	~~LS35~~	~~This change increases the RCP seal injection flow Completion Time from 4 to 72 hours, with a new added verification that at least 100% of the assumed charging flow remains available. The Bases for the seal injection flow limit relates to ensuring adequate charging flow during post-LOCA injection. The revised ACTIONS continue to assure this basis is adequately addressed by providing an ECCS-like Required Action. ITS Specification 3.5.2 allows a 72 hour Completion Time for one or more ECCS subsystems inoperable if at least 100% of the assumed ECCS flow is available. The seal injection flow ACTIONS have been modified so that if the remaining charging flow (with some inoperability in the charging system) is greater than or equal to 100% of the assumed post-LOCA charging flow, 72 hours is allowed to restore OPERABILITY. This change is consistent with Industry Traveler WOG-84.~~ Not Used
06-22	M	Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B).
06-23	LS25	CTS 3.4.6.1, "Leakage Detection Systems", is revised such that the provisions of Specification 3.0.4 are not applicable. This will allow entry into the applicable MODES with only one of the Leakage Detection Systems OPERABLE, subject to the requirements of the ACTION statements. This change is consistent with NUREG-1431 and Industry Traveler TSTF-60 and is acceptable because of the diverse means available to detect RCS leakage. Insert Q3.4.15-1
06-24	M	Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B).
06-25	LS26	The Operational Leakage LCO has been modified to change the allowed leakage limit for RCS PIVs for consistency with improved TS SR 3.4.14.1. The RCS PIV LCO permits system operation in the presence of leakage through valves in amounts that do not compromise safety. Insert Q3.4.13-1
06-26	LS30	The CTS surveillance requirement for performing a RCS water inventory balance is modified to allow deferral of the water inventory balance such that it would be performed within 12 hours after achieving steady state conditions. The RCS water inventory balance must be performed with the reactor at steady state conditions as discussed in the ITS Bases. This change is in conformance with Industry Traveler TSTF 116, Rev. 1.
06-27	A	Not applicable to DCPP See Conversion Comparison Table (Enclosure 3B).
06-28	LG	Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B).
07-01	R	Not applicable to DCPP. See Conversion Comparison Table (Enclosure 3B).
06-29	LS38	Insert
06-30	A	Insert

Q3.4.14-3

CONVERSION COMPARISON TABLE - CURRENT TS 3/4.4

TECHNICAL SPECIFICATION CHANGE		APPLICABILITY			
NUMBER	DESCRIPTION	DIABLO CANYON	COMANCHE PEAK	WOLF CREEK	CALLAWAY
06-16-LS 14	This change removes the requirement for monitoring the reactor head flange leakoff system.	Yes	Yes	Yes	Yes
06-17-LG	The definition of steady state is moved to the Bases.	Yes	Yes	No, WCGS did not have this definition.	No, Callaway did not have this definition.
06-18-LS 15	This change relaxes the requirement for PIV testing following operation in MODE 5. The previous requirement was testing following 72 hours in MODE 5 which is revised to 7 days in MODE 5.	No, MODE 5 testing requirement is not part of CTS.	Yes	Yes	No, already in CTS per Amendment 05.
06-19-TR 3	This change removes the specific requirement for performing the PIV surveillance prior to returning a valve to service following maintenance, repair or replacement.	Yes	Yes	Yes	Yes
06-20-A	IST requirements are moved to Administrative Controls Section 5.5.8 of the improved ITS.	Yes	Yes	No, WCGS does not have this requirement.	No, Callaway does not have this requirement.
06-21~~-LS~~ ~~35~~	~~This change increases the RCP seal injection flow Completion Time from 4 to 72 hours, with a new added verification that at least 100% of the assumed charging flow remains available.~~ → Not Used	~~Yes~~ NA	~~Yes~~ NA Q3.5.5-1	~~No, see CN 06-28-LG~~ NA	~~No, see CN 06-28-LG~~ NA
06-22-M	This change adds a new ACTION to isolate the affected RHR penetration within 4 hours if the RHR suction isolation valve interlock function is inoperable.	No, not part of current DCPP TS.	Yes	Yes	Yes
06-23-LS 25	The leakage detection system specification is revised such that the provisions of 3.0.4 are not applicable and two monitoring systems can be inoperable without invoking LCO 3.0.3.	Yes	No, the non-applicability of 3.0.4 is already part of the CTS.	Yes	Yes Q3.4.15-1
06-24-M	Revises ACTION to require going to COLD SHUTDOWN rather than HOT SHUTDOWN with an RCS pressure less than 600 psig.	No, the 600 psig ACTION is not part of the CTS.	No, the 600 psig ACTION is not part of the CTS.	Yes	Yes

Q3.5.5-1

IV. SPECIFIC NO SIGNIFICANT HAZARDS CONSIDERATIONS

NSHC LS35
10 CFR 50.92 EVALUATION FOR SPECIFIC LESS RESTRICTIVE TECHNICAL CHANGE

Not Used

This change increases the seal injection flow Completion Time from 4 to 72 hours, with a new added verification that at least 100% of the assumed charging flow remains available. The Bases for seal injection flow relate the limit to ensuring adequate charging flow during post-LOCA injection. The revised ACTIONS continue to assure this basis is adequately addressed by providing an ECCS-like Required Action. Specification 3.5.2 allows a 72 hour Completion Time for one or more ECCS subsystems inoperable if at least 100% of the assumed ECCS flow is available. The seal injection flow ACTIONS have been modified so that if the remaining charging flow (with some inoperability in the charging system) is greater than or equal to 100% of the assumed post-LOCA charging flow, 72 hours is allowed to restore OPERABILITY. This change is consistent with Industry Traveler WOG-84.

This proposed TS change has been evaluated and it has been determined that it involves no significant hazards consideration. This determination has been performed in accordance with the criteria set forth in 10 CFR 50.92(c) as quoted below:

> *"The Commission may make a final determination, pursuant to the procedures in 50.91, that a proposed amendment to an operating license for a facility licensed under 50.21 (b) or 50.22 or for a testing facility involves no significant hazards consideration, if operation of the facility in accordance with the proposed amendment would not:*
>
> 1. *Involve a significant increase in the probability or consequences of an accident previously evaluated; or*
>
> 2. *Create the possibility of a new or different kind of accident from any accident previously evaluated; or*
>
> 3. *Involve a significant reduction in a margin of safety."*

The following evaluation is provided for the three categories of the significant hazards consideration standards:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change revises the completion time for restoring seal injection flow from 4 hours to 72 hours. The basis of this completion time is to ensure availability of the assumed post-LOCA charging flow. To compensate for the increased completion time, a new requirement is added to verify, within 4 hours, that at least 100% of the assumed post-LOCA charging flow is available. Since the change continues to ensure 100% of the assumed charging flow is available, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   There are no hardware changes nor are there any changes in the method by which any safety-related plant system performs its safety function. Since the change continues to ensure 100% of the assumed charging flow is available, no new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

Q355-1

Not Used

~~NSHC LS35~~
~~(Continued)~~

3. ~~Does this change involve a significant reduction in a margin of safety?~~

~~The proposed change does not affect the acceptance criteria for any analyzed event. There will be no effect on the manner in which safety limits or limiting safety system settings are determined nor will there be any effect on those plant systems necessary to assure the accomplishment of protection functions. Since the change continues to ensure 100% of the assumed charging flow is available there will be no impact on any margin of safety.~~

~~NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION~~

~~Based on the above evaluation, it is concluded that the activities associated with NSHC "LS 35" resulting from the conversion to the improved TS format satisfy the no significant hazards consideration standards of 10 CFR 50.92(c); and accordingly, a no significant hazards consideration finding is justified.~~

Industry Travelers Applicable to Section 3.5

TR 3.5-001

TRAVELER #	STATUS	DIFFERENCE #	COMMENTS
TSTF-90, Rev. 1	Incorporated	3.5-6	Approved by NRC.
TSTF-117, Rev. 2	Incorporated	3.5-1	Approved by NRC.
TSTF-153	Incorporated	3.5-8	Approved by NRC.
~~TSTF-155~~	~~Not Incorporated~~	~~N/A~~	~~Not NRC approved as of traveler cut-off date~~.
~~WOG-84~~ TSTF-236	Incorporated	3.5-4	DCPP and CPSES only.

Q3.5.5-1

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.5 Seal Injection Flow

LCO 3.5.5 Reactor coolant pump seal injection flow shall be ≤~~[~~ 40~~]~~ gpm with [~~centrifugal charging pump discharge header]~~ RCS pressure ≥ ~~[2480~~ 2215 psig and ≤2255 psig~~]~~ and the ~~[~~charging flow~~]~~ control valve full open.

B

3.5-5

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Seal injection flow not within limit.	~~A.1 Verify ≥100% flow equivalent to a single OPERABLE ECCS charging train is available~~ ~~AND~~ A.~~2~~ ① Adjust manual seal injection throttle valves to give a flow within limit with [~~centrifugal charging pump discharge header~~] RCS pressure ≥ ~~[2480~~ 2215 psig and ≤2255~~]~~ psig and the ~~[~~charging flow~~]~~ control valve full open.	~~4 hours~~ ~~72~~ ④ hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

~~3.5-4~~

Q3.5.5-1

3.5-5

B

BASES

LCO
(continued)

With the ~~discharge~~ RCS pressure and control valve position as specified by the LCO, a flow limit is established which assures that the seal injection line resistance is consistent with the analysis assumptions. ~~a limit is established. It is this line limit resistance that is used in the accident analyses.~~ This limit assures that when the RCS depressurizes following a LOCA and the flow to the pump seals increases, the resulting flow to the seals will be less than the limit assumed in the accident analysis.

redline

~~flow~~

~~The limit on seal injection flow, combined with the CCP discharge header pressure limits and an open wide condition of the charging flow control valve, must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.~~

APPLICABILITY

3.5.G-1

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in ~~these~~ ~~this~~ MODE 4. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1 ~~and A.2~~

Q3.5.5-1

With the seal injection flow exceeding its limit, the amount of charging flow available for ECCS injection to the RCS may be reduced. Under this Condition, action must be taken to restore the seal injection flow to below its limit. ~~Required Action A.1 ensures that within 4 hours the remaining available ECCS charging flow (without assuming an additional failure) is ≥ 100% of the assumed post-LOCA charging flow. 100% flow capability may be verified by assuring both CCPs are OPERABLE. Required Action A.2 then allows~~ the operator ~~has 4~~ ~~72~~ hours from the time the flow is known to be above the limit ~~but still allowing 100% of the assumed post-LOCA ECCS charging flow,~~ to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is ~~conservative~~ ~~consistent~~ with ~~respect to~~ the Completion Times ~~for ECCS in 3.5.2, ACTION A.~~ ~~of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.~~

has 4

conservative

for other ECCS LCOs.

(continued)

JUSTIFICATION FOR DIFFERENCES FROM NUREG-1431

NUREG-1431 Section 3.5

This Enclosure contains a brief discussion/justification for each marked-up technical change to NUREG-1431, to make them plant-specific or to incorporate generic changes resulting from the Industry/NRC generic change process. The change numbers are referenced directly from the NUREG-1431 mark-ups (Enclosure 5A). For Enclosures 3A, 3B, 4, 6A, and 6B text in brackets "[ ]" indicates the information is plant specific and is not common to all the JLS plants. Empty brackets indicate that other JLS plants may have plant specific information in that location.

CHANGE NUMBER	JUSTIFICATION
3.5-1	This change replaces reference to the "pressurizer pressure" with a reference to the "RCS pressure" in the APPLICABILITY, Required Action C.2, and SR 3.5.1.5. Required ACTION C.2 requires reducing pressurizer pressure to less than 1000 psig. However, pressurizer pressure instrumentation does not have the range to read that pressure. Consequently, RCS pressure instrumentation is used. For the purposes of this LCO, the use of RCS pressure is equivalent. This is consistent with Industry Traveler 117.
3.5-2	Not applicable to Diablo Canyon Power Plant (DCPP). See Conversion Comparison Table (Enclosure 6B).
3.5-3	This change adds the word "mechanical" with regard to throttle valve position stop, consistent with the CTS. These valves have mechanical stops that maintain the valves in position for proper ECCS performance.
3.5-4	Q3.5.5-1 ~~This change increases the RCP seal injection flow Completion Time from 4 to 72 hours, with a new added verification that at least 100 percent of the assumed charging flow remains available. The Bases for seal injection flow relate the limit to ensuring adequate charging flow during post-LOCA injection. The revised ACTIONS continue to assure this basis is adequately addressed by providing an ECCS-like Required Action. ITS 3.5.2 allows a 72 hour Completion Time for 1 or more ECCS subsystems inoperable if at least 100 percent of the assumed ECCS flow is available. The seal injection flow ACTIONS have been modified so that if the remaining charging flow (with some inoperability in the charging system) is greater than or equal to 100 percent of the assumed post-LOCA charging flow, 72 hours is allowed to restore OPERABILITY. This change is consistent with industry Traveler~~ ~~WOG-04~~. ~~TSTF-236~~ Not Used TR 35-001
3.5-5	This change deleted reference to CCP discharge header pressure from the LCO and ACTION A to reflect CTS [3.4.6.2.]. A description is added to the Bases which provides the methodology for adjusting the seal injection throttle valves consistent with plant-specific analyses.

CONVERSION COMPARISON TABLE FOR DIFFERENCES FROM NUREG-1431, SECTION 3.5 Page 1 of 1

TECHNICAL SPECIFICATION CHANGE		APPLICABILITY			
NUMBER	DESCRIPTION	DIABLO CANYON	COMANCHE PEAK	WOLF CREEK	CALLAWAY
3.5-1	Replaced "pressurizer pressure" with "RCS pressure."	Yes	Yes	Yes	Yes
3.5-2	The Completion Time of LCO 3.5.1, Condition B, is changed from 1 hour to 24 hours to reflect the CTS.	No, not part of the CTS.	No, not part of the CTS.	~~Yes, license Amendment pending.~~ No, not part of CTS.	Yes, CTS per OL Amendment No. 91. Q 3.5.1-2
3.5-3	Adds the word" mechanical" with regard to throttle valve position stop consistent with the CTS.	Yes	Yes	Yes	Yes
3.5-4	~~This change increases the RCP seal flow Completion Time from 4 to 72 hours, with a new added verification that at least 100 percent of the assumed charging flow remains available.~~ → Not Used	~~Yes~~ NA Q3.5.5-1	~~Yes~~ NA	~~No, LCO 3.5.5 is not applicable.~~ NA	~~No, LCO 3.5.5 is not applicable.~~ NA
3.5-5	Deleted reference to CCP discharge header pressure to reflect CTS.	Yes	Yes	No, not part of the CTS.	No, not part of the CTS.
3.5-6	SR 3.5.3.1 Note is moved to LCO per Traveler TSTF-90.	Yes, per LAR 96-03.	Yes	Yes	Yes
3.5-7	Not used.	N/A	N/A	N/A	N/A
3.5-8	Moves the Notes from the "APPLICABILITY" to the "LCO." Also revises the wording in Note 2 from "declared inoperable" to "made incapable of injecting."	No, not part of CTS.	Yes	Yes	Yes
3.5-9	The seal injection/return valves (BGV0198-BGV0202) are included in ITS SR 3.5.2.7 since they are included in CTS 4.5.2.g.2.	No, not part of the CTS.	No, not part of the CTS.	Yes	Yes

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: CA 3.5-002 **APPLICABILITY:** CA, CP, DC, WC

REQUEST (original): Revise ITS 3.5.4 Bases to indicate that the RWST LCO, by virtue of its temperature, volume, and boron concentration limits, also satisfies Criterion 2 (initial conditions of accident analyses).

REQUEST (revised): Revise various additional ITS Bases regarding the correct application of Criterion 2 of 10CFR50.36(c)(2)(ii). These changes are consistent with the attachment to a May 9, 1988, letter from T.E. Murley (NRC) to R.A. Newton (WOG) entitled "NRC Staff Review of NSSS Vendor Owners Groups' Application of the Commission's Interim Policy Statement Criteria to Standard Technical Specifications."

1. Revise ITS 3.5.1 Bases to indicate that the Accumulators LCO, by virtue of its pressure, volume, and boron concentration limits, also satisfies Criterion 2 (initial conditions of accident analyses).

2. Revise ITS 3.5.4 Bases to indicate that the RWST LCO, by virtue of its temperature, volume, and boron concentration limits, also satisfies Criterion 2 (initial conditions of accident analyses).

3. Revise ITS 3.6.7 Bases to indicate that the Recirculation Fluid pH Control (RFPC) System, by virtue of its TSP-C depth limit which ensures a minimum equilibrium sump pH of 7.1, also satisfies Criterion 2 (initial conditions of accident analyses). (Callaway only)

4. Revise ITS 3.7.6 Bases to indicate that the CST (and FWST for DCPP) LCO, by virtue of its water volume limit, also satisfies Criterion 2 (initial conditions of accident analyses).

ATTACHED PAGES:

Attachment 11, CTS 3/4.5 / ITS 3.5

Encl 5B B 3.5-4 and B 3.5-31

Attachment 13, CTS 3/4.7 / ITS 3.7

Encl 5B B 3.7-35

APPLICABLE SAFETY ANALYSES (continued)

in water volume is a peak clad temperature penalty. ~~For large breaks~~ **Depending on the NRC-approved methodology used to analyze large breaks**, an increase in water volume ~~can~~ **may** ~~be~~ result in either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis makes a conservative assumption with respect to ignoring or taking credit for line water volume from the accumulator to the check valve. The safety analysis assumes values of ~~≥[6468]~~ 60.8% (836 cubic feet) ~~gallons~~ and ~~≤[6879]~~ 72.6% (864 cubic feet) ~~gallons~~ as read on narrow range level instruments, not including instrument uncertainty. ~~To allow for instrument inaccuracy values of [6520] gallons and [6820] gallons are specified.~~

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction ~~in~~ **below** the accumulator LCO minimum boron concentration would produce a subsequent reduction in the available containment recirculation sump boron concentration for post LOCA shutdown and an increase in the ~~maximum~~ sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure (~~603 psia~~)**(595.5 psig)**, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit (~~693 psia~~) **(647.5 psig)** ~~prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.~~ provides margin to assure inadvertent relief valve actuation does not occur.

These analysis-assumed pressures are specified in the SRs. Volumes are shown on the control board indicators as % readings on accumulator narrow range level instruments. Adjustments to the analysis parameters for instrument inaccuracies or other reasons are applied to determine the acceptance criteria used in the plant surveillance procedures. These adjustments assure the assumed analyses parameters are maintained.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. ② ① and ④ ③). CA3.5-001

The accumulators satisfy Criterion 2 and Criterion 3 of ~~the NRC Policy Statement.~~ 10 CFR 50.36(c)(2)(ii). CA3.5-002

APPLICABLE SAFETY ANALYSES (continued)

Steam Generator Tube Rupture (SGTR)

Volume

The RWST volume needed in response to a SGTR is not an explicit assumption since the required volume is much less than that required by a LOCA.

Boration

Borated RWST water will be injected into the RCS for a SGTR event. The insertion of the control rods and the negative reactivity provided by the injected RWST solution provides sufficient SDM during the initial recovery operations. One of the initial operator recovery actions for this event is to equalize the RCS pressure and the faulted steam generator pressure to minimize or stop the primary-to-secondary tube rupture flow and terminate safety injection. Further RCS boration will be initiated by the operator by manual makeup to the RCS.

CA 3.5-002

The RWST satisfies ~~Criterion~~ criteria 2 and 3 of ~~the NRC Policy Statement~~ 10 CFR 50.36(c)(2)(ii).

Insert 3

DC 3.5-005

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment recirculation sump to support ECCS ~~and Containment Spray System~~ pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and CS ~~Containment Spray~~ System OPERABILITY requirements. Since both the ECCS and the CS ~~Containment Spray~~ System~~s~~ must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual

DC 3.5-ED

(continued)

requires more AFW supply than can be provided by the seismically qualified portion of the CST.

~~The limiting event for the~~ Other events requiring condensate volume ~~is~~ are:

1) the large feedwater line break coincident with a loss of offsite power. Single failures that also affect this event include the following:

   a. Failure of the diesel generator powering the motor driven AFW pump to the unaffected steam generator (requiring additional steam to drive the remaining AFW pump turbine); and

   b. Failure of the steam driven AFW pump (requiring a longer time for cooldown using only one motor driven AFW pump).

   These are not usually the limiting failures in terms of consequences for these events.

~~A nonlimiting event considered in CST inventory determinations is~~ and,

2) a break in either the main feedwater or AFW line near where the two join. This break has the potential for dumping condensate until terminated by operator action, since the Emergency Feedwater Actuation System would not detect a difference in pressure between the steam generators for this break location. This loss of condensate inventory is partially compensated for by the retention of steam generator inventory.

The CST and FWST satisf~~ies~~y Criteri~~on~~a 2 and 3 of ~~the NRC Policy Statement.~~ 10 CFR 50.36 (c) (2) (ii). Q3.7.6-1

red-line CA 3.5-002

LCO

To satisfy ~~accident~~ losgri analysis assumptions, the CST and FWST must contain sufficient cooling water to remove decay heat ~~for [30 60 minutes]~~ following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine~~, or before isolating AFW to a broken line~~.

The CST level required is equivalent to a usable volume of ~~≥ [110,000 gallons]~~ 41.3% indicated level (164,678 gallons)~~,~~. ~~which is~~ The FWST level required is equivalent to a usable volume

(continued)

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: DC 3.5-002 **APPLICABILITY:** DC

REQUEST (original): Revise ITS SR 3.5.5.1 by adding a second note that states: "The provisions of specification SR 3.0.4 are not applicable for entry into MODE 3." This note is equivalent to the current technical specification 4.4.6.2.1 c. note except that it does not apply to MODE 4 entry since ITS 3.5.5 does not apply to MODE 4.

REQUEST (revised): Diablo Canyon will no longer pursue this change. It is interpreted that ITS SR 3.5.5.1 Note 1 is essential equivalent to the previously proposed added Note 2. Therefore, Note 2 will be deleted.

ATTACHED PAGES:

Attachment 11 - CTS 3/4.5 / ITS 3.5

Encl. 5A	3.5-11
Encl. 5B	B3.5-38

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.5.5.1	------------------NOTES------------------ ① Not required to be performed until 4 hours after the Reactor Coolant System pressure stabilizes at ≥ ~~[~~2215 psig and ≤ 2255 psig. ~~]~~ ② ~~The provisions of SR 3.0.4 are not applicable for Entry into MODE 3.~~ -- Verify manual seal injection throttle valves are adjusted to give a flow within limit with ~~[centrifugal charging pump discharge header~~] RCS pressure ≥~~[~~ ~~2480~~ 2215 psig and ≤ 2255~~]~~ psig and the ~~[charging flow]~~ control valve full open.	~~DC 3.5-002~~ B 31 days B 3.5-5

BASES

ACTIONS
(continued)

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the plant shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4, where this LCO is no longer applicable.

SURVEILLANCE
REQUIREMENTS

SR 3.5.5.1

Verification every 31 days that the manual seal injection throttle valves are adjusted to give a flow ~~within~~ below the limit ensures ~~that~~ proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. The Frequency of 31 days is based on engineering judgment and is consistent with other ECCS valve Surveillance Frequencies. The Frequency has proven to be acceptable through operating experience.

As noted, the Surveillance is ~~not required~~ to be ~~performed until~~ **completed within** 4 hours after the RCS pressure has stabilized within ~~) ± 20 psig range of normal operating~~ the **specified** pressure **limits**. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

~~JC 3.5-02~~

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.
2. 10 CFR 50.46.

~~This Surveillance is further modified by Note 2 that states that the provisions of SR 3.0.4 are not applicable for entry into MODE 3.~~

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: DC 3.5-006 **APPLICABILITY:** DC

REQUEST (original): Revise the SR Bases 3.5.2.3 to clarify what is required to verify that the ECCS piping is full of water.

ATTACHED PAGES - additional changes were made to Enclosure 5B ("adequately vented" replaces "full of water")

Attachment 11 - CTS 3/4.5 / ITS 3.5

Encl. 5B B 3.5-17

SURVEILLANCE REQUIREMENTS (continued)

for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

With the exception of the operating CCP ~~centrifugal charging pump~~, the ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the piping from the ECCS pumps to the RCS full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent water hammer, pump cavitation, gas binding and pumping of non-condensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

The intent of the SR is to assure the ECCS piping is ~~full of water~~ adequately vented. Different means of verification, as alternates to venting the accessible system high points, can be employed to provide this assurance ① such as verifying full the vent lines of the ECCS pump casings (for non-running pumps) and accessible high point vents.

DC 3.5-006

~~Venting of the accessible ECCS high points prior to entering MODE 3 ensures the system is full of water and will perform properly, injecting its full capacity into the RCS on demand.~~

~~The CCP design and attached piping configuration allow the CCP to vent the accumulated gases via the attached suction and discharge piping. Continuous venting of the suction piping to the Volume Control tank (VCT) and manual venting of the discharge piping high points satisfies the pump casing venting requirements for the CCPs.~~

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by

ADDITIONAL INFORMATION COVER SHEET

ADDITIONAL INFORMATION NO: NR 5.0-001 **APPLICABILITY:** DC, CP, CA, WC

REQUEST: The NRC requested the following:

For the following plants (and CTS sections), the applications identify the CTS requirements are being relocated to the FSAR: CW (6.2.3, ISEG; 6.5 , review and audit; 6.10.1, record retention); CP (none); DC (6.10.1, record retention); and WC (6.2.3, ISEG; 6.5, review and audit; 6.8.2.3, procedure changes; 6.10.1, record retention). We discussed relocations to the QA plan with Ray Smith (QA branch) several weeks ago. The staff needs to have the licensees identify that these requirements are going to the QA plan and thus controlled by 50.54(a). The DOCs for relocating the above CTS sections are 1-04-LG and 3-09-LG. These DOCs only state the relocation is to the FSAR. The relocation should be to the QA plan.

FLOG RESPONSE: Enclosures 3A and 3B has been updated to reflect the location of subject relocated items.

ATTACHED PAGES:

Attachment 18 - CTS 6.0 / ITS 5.0

Encl. 3A	6
Encl. 3B	7

DESCRIPTION OF CHANGES TO TS SECTION 6.0

(Continued)

CHANGE NUMBER	NSHC	DESCRIPTION
03-06	A	CTS [6.9.1.6], "Annual Radioactive Effluent Release Report" and CTS [6.14c.] are revised consistent with NUREG-1431, Rev. 1, to delete the term "Annual" and modify the submittal date. This change provides a reference to 10CFR 50.36a since 10CFR specifies that the report must be submitted annually and include the results from the previous 12 months of operation.
03-07	A	CTS [6.9.1.5], "Annual Radiological Environmental Operating Report" is revised to include specific details concerning the contents of the report. This change is consistent with NUREG-1431, Rev. 1.
03-08	A	CTS Specifications [6.9.1.7, 6.9.1.8 and 6.9.2] are revised to delete the reference to submittal location for the monthly report, CORE OPERATING LIMITS REPORT (COLR), and special reports. The requirements related to report submittal are contained in 10CFR. Since conformance to 10CFR is a condition of the license, specific identification of this requirement in the TS would be duplicative and is not necessary. Since the plant requirements remain the same, the change is considered an administrative change. This change is consistent with NUREG-1431, Rev. 1.
03-09	LG	NR5.0-001 The record retention requirements are moved to ~~the FSAR and implementing procedures~~ a licensee controlled document. The removal of this detail from the CTS is consistent with NUREG-1431. The requirement for retention of records related to activities affecting quality is contained in 10CFR 50, Appendix B, Criteria XVII and other sections of 10CFR 50 that are applicable to the plant (i.e., 50.71, etc.). Post-completion review of records does not directly assure operation of the facility in a safe manner, as the activities described in the documents have already been performed. By retaining these requirements in ~~plant procedures and~~ a licensee controlled document~~s~~, any changes in these record retention requirements will be adequately controlled under the provisions of 10CFR ~~50.59~~ 50.54(a) and the applicable regulations.
03-10	LG	The Radiation Protection Program is moved to the FSAR consistent with NUREG-1431. This program requires procedures to be prepared for personnel radiation protection consistent with 10CFR Part 20. These procedures are for the protection of nuclear plant personnel and have no impact on nuclear safety or the health and safety of the public. Requirements to have procedures to implement 10CFR Part 20 are contained in 10CFR 20.1101(b). Periodic review of these procedures is required by 10CFR 20.1101(c). The CTS is redundant to requirements in the regulations and thus is deleted.
03-11	A	~~The high radiation area is revised to be consistent with NUREG-1431 and the new Part 20 requirements. Changes are nontechnical to add clarification and conform with NUREG-1431 and RG 8.38.~~ Insert Q5.2-1

CONVERSION COMPARISON TABLE - CURRENT TS 6.0

TECH SPEC CHANGE		APPLICABILITY			
NUMBER	DESCRIPTION	DIABLO CANON	COMANCHE PEAK	WOLF CREEK	CALLAWAY
03-06 A	CTS [6.9.1.6], "Annual Radioactive Effluent Release Report," and CTS [6.14c.] are revised consistent with NUREG-1431, Rev. 1, to delete the term "Annual" and modify the submittal date.	Yes	Yes	Yes	Yes
03-07 A	CTS [6.9.1.5], "Annual Radiological Environmental Operating Report," is revised to include specific details concerning the contents of the report.	Yes	Yes	Yes	Yes
03-08 A	CTS Specification [6.9.1.7, 6.9.1.8 and 6.9.2] are revised to delete the reference to submittal location for the monthly report, CORE OPERATING LIMITS REPORT, and special reports.	Yes	Yes	Yes	Yes
03-09 LG	The record retention requirements are moved to ~~the FSAR and implementing procedures~~ a licensee controlled document. The requirement for retention of records related to activities affecting quality is contained in 10CFR 50, Appendix B, Criteria XVII, and other sections of 10CFR 50 that are applicable to the plant (i.e., 50.71, etc.).	Yes - QA Plan in Chapter 17 of the FSAR.	Yes - QA Plan in Chapter 17 of the FSAR.	Yes - QA Plan in Chapter 17 of the USAR.	Yes - QA Plan in Chapter 17 of the FSAR. NR5.0-001
03-10 LG	The Radiation Protection Program is moved to the FSAR. This program requires procedures to be prepared for personnel radiation protection consistent with 10CFR Part 20. Periodic review of these procedures is required by 10CFR 20.1101(c).	Yes	No, deleted from CTS per Amendment 50/36.	Yes	Yes
03-11 A	The High Radiation Area section is revised to be consistent with the new Part 20 requirements. Changes are nontechnical to add clarification.	Yes	Yes	Yes	Yes
03-12 LG	The PCP section is proposed to be moved outside the CTS. The PCP implements the requirements of 10CFR 20, 10CFR 61, and 10CFR 71.	Yes, move to FSAR.	No, deleted from CTS per Amendment 50/36.	Yes, move to USAR.	Yes, move to FSAR.

127088

126.14

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415 972 7000
TWX 910 372 6587

James D. Shiffer
Vice President
Nuclear Power Generation

March 10, 1989

PG&E Letter No. DCL-89-060

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Diablo Canyon Unit 1
Licensee Event Report 1-88-004-00 - VOLUNTARY
Control Rod Drive Mechanism (CRDM) Canopy Seal Weld Leaks Due to Transgranular Stress Corrosion Cracking

Gentlemen:

PG&E is submitting the enclosed voluntary Licensee Event Report concerning CRDM canopy seal weld leakage. This report is being submitted for information purposes only as described in Item 19, of Supplement Number 1, to NUREG-1022.

This event has in no way affected the public's health and safety.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Sincerely,

J. D. Shiffer

cc: J. B. Martin
M. M. Mendonca
P. P. Narbut
B. Norton
H. Rood
B. H. Vogler
CPUC
Diablo Distribution
INPO

Enclosure

DC1-88-MM-N025

2546S/0067K/DY/2246

RECEIVED
MAR 13 1989
JMW
Corresp. Control Center

8903170155 8pp

127088

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): DIABLO CANYON UNIT 1

DOCKET NUMBER (2): 0 5 0 0 0 2 7 5

PAGE (3): 1 OF 0 7

TITLE (4): CONTROL ROD DRIVE MECHANISM (CRDM) CANOPY SEAL WELD LEAKS DUE TO TRANSGRANULAR STRESS CORROSION CRACKING

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	2 5	8 8	8 8	0 0 4	0 0	0 3	1 0	8 9		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 6 8

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (11)

☒ [illegible] VOLUNTARY

☐ OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

TERRY GREBEL, REGULATORY COMPLIANCE SUPERVISOR

TELEPHONE NUMBER: AREA CODE 8 0 5 5 9 5 - 4 7 2 0

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

☐ YES (If yes, complete EXPECTED SUBMISSION DATE) ☒ NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

This voluntary LER is being submitted for information purposes only as described in Item 19, of Supplement Number 1, to NUREG-1022.

On February 25, 1988, with the Unit in Mode 1 (Power Operation), an unexplained increase in containment airborne radiation was observed. On March 12, 1988, following plant shutdown, examination of the reactor vessel head duct work disclosed a leak in the canopy seal weld of the Control Rod Drive Mechanism (CRDM) head adapter plug at spare location L-5. Subsequent visual inspections revealed additional canopy seal weld leaks at spare locations L-9, L-11, and J-5.

From April 8 through April 21, 1988, the identified head adapters were removed and replaced with caps welded in place. All repairs were determined to be satisfactory and constituted a permanent repair for these locations.

The metallurgical examinations performed on the head adapters removed from locations J-5, L-9, and L-11, indicated that the leaks were initiated at the inside diameter of the canopy and were caused by transgranular stress corrosion cracking. STP R-8A, "Reactor Coolant System Operational Pressure Leak Test", was revised to include a CRDM inspection.

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NRC Form 366A
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	PAGE (3)
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	8 8	—	0 0 4	—	0 0	0 2 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. Initial Conditions

Unit 1 was in Modes 1 through 6 during this event.

II. Description of Event

A. Event:

On February 25, 1988, with the Unit in Mode 1 (Power Operation), an unexplained increase in the Unit 1 containment airborne radiation level was observed. Examination of daily containment air samples, both noble gas and radio-particulate, substantiated this increase. However, there was no significant increase in reactor coolant system leakage as calculated during the regular daily performance of Surveillance Test Procedure (STP) R-10B, "Containment Sump Inventory and Discharge - (12 Hrs) - Data Evaluation," and R-10C, "Reactor Coolant System Water Inventory Balance (72 Hrs)".

The increase in noble gas activity persisted until the end of the refueling cycle. On March 12, 1988, during the refueling outage, higher than anticipated reactor vessel head (RPV) duct work radioactive contamination levels were observed. During the course of investigating these higher levels of contamination on March 12, a leak was observed in the canopy seal weld of the Control Rod Drive Mechanism (CRDM) (AA) head adapter plug at spare location L-5. The leak was characterized by deposits of boric acid and rust colored material extending down the CRDM housing.

On March 15 and 16, interviews were conducted with the two individuals who discovered the leak. From these interviews, it was noted that the canopy seal weld of the CRDM head adapter plug at spare location L-5 was still weeping at the time of discovery on March 12. No other leaks were visible. Their observations indicated that a minimal amount of boric acid had leaked onto the reactor vessel head insulation. A follow-up remote visual inspection of the Unit 1 head area revealed a possible leaking weld at spare location J-5.

On March 16, due to concerns about possible similar leaks on Unit 2, smear samples were taken from the Unit 2 CRDM fan ducts. Analysis of these samples revealed that they were consistent with the smear surveys performed on the CRDM fans during the Unit 2 first refueling outage. In addition to smears, daily grab sample data and noble gas data from June 1987 through March 1988 was examined with no increasing trends. These three evaluations provided assurance that there was no similar leakage in Unit 2.

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NRC Form 366A
(9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	8 8	— 0 0 4 —	0 0	0 3 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

From April 2 through April 4, Westinghouse personnel conducted a full visual examination of all 79 canopy seals using a Welch-Allyn videoprobe (TVC). This examination confirmed leakage at location J-5 and identified potential leaks at locations L-9, L-11, L-7, and E-7.

Subsequent review of the videotapes by Westinghouse and PG&E personnel determined that in addition to leaks at spare locations J-5 and L-5, welds at spare locations L-9 and L-11 had minute leaks and should also be repaired. Canopy seal weld at spare location L-7 was identified as requiring more study and E-7 was determined to have no through-wall leakage.

From April 8 through April 21, spare adapters at locations J-5, L-5, L-9, and L-11 were removed and caps welded on using full penetration butt welds. The canopy seal weld at L-7 was later determined radiographically to have no through-wall indications.

The RCS was returned to operating temperature and pressure at the end of the refueling outage, at which time STP R-8A, "Reactor Coolant System Operational Pressure Leak Tests," was performed. No additional canopy seal weld leaks were noted.

B. Inoperable structures, components, or systems that contributed to the event:

None

C. Dates for major occurrences:

1.	February 25, 1988:	Event Date-Increase in Unit 1 containment radiation levels.
2.	March 12, 1988:	During removal of fan duct work, substantially higher than anticipated contamination levels were discovered.
3.	March 12, 1988:	Discovery Date-Boric acid discovered on Unit 1 CRDM housing at penetration L-5.
4.	March 16, 1988:	Smear samples were taken from the Unit 2 CRDM fan ducts. Daily grab sample data and noble gas data was examined. Results indicate that Unit 2 did not have leaking canopy seal welds. Visual inspection of the Unit 1 vessel head confirmed penetration L-5 was leaking. An additional leak was discovered at head adapter plug at spare location J-5.

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NRC Form 366A
(9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	8 8	— 0 0 4 —	0 0	0 4 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

5. April 2-4, 1988: Detailed visual inspection of the Unit 1 vessel head identified head adapter plugs at spare locations L-9, L-7, E-7 and L-11 as potentially leaking. Subsequent review confirmed leaks at L-9 and L-11, and no leakage at E-7.

6. April 8-21, 1988: Head adapter plugs at spare locations L-9, L-11, J-5, and L-5 were repaired using the "cut off and cap" method. Radiography determined that L-7 had no through-wall indications.

7. July/August, 1988: Canopy seal welds L-9, L-11, and J-5 were metallurgically examined by Westinghouse and General Electric for root cause determination.

D. Other systems or secondary functions affected:

None

E. Method of discovery:

During an investigation of higher than anticipated radioactive contamination levels in the reactor vessel head duct work, a leak was discovered in the canopy seal weld of the CRDM adapter plug at spare location L-5. A follow-up remote visual examination revealed a possible leaking weld at spare location J-5. A detailed visual examination of the Unit 1 vessel head was performed. This inspection confirmed the leak at J-5, and identified leaking canopy seal welds at locations L-9 and L-11 as well.

F. Operator actions:

None required

G. Safety system responses:

None

III. <u>Cause of Event</u>

A. Immediate cause:

The leaks through the CRDMs were caused by cracks in the canopy seal welds of the CRDM head adapter plugs at spare locations J-5, L-5, L-9 and L-11.

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NRC Form 366A
(9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)	
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER		
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	8 8	— 0 0 4 —	0 0	0 5	OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

B. Root cause:

On March 14, 1988, an Event Investigation Team (EIT) was formed to collect and evaluate the pertinent design, operation, installation and inspection data required to establish a root cause and to recommend corrective action. As part of this effort Westinghouse and General Electric were contracted to perform metallurgical evaluations on the leaking canopy seal welds at space locations J-5, L-9, and L-11. These metallurgical examinations of canopy seal welds confirmed that the leaks were caused by transgranular stress corrosion cracking. The failures were not associated with weld repairs and were not the result of fatigue. It is postulated that the stress corrosion cracking was a result of concentrations of contaminants (chlorides and sulfates) in the stagnant liquid in the canopy annulus and in the crevices formed by the lack of weld penetration. Chemical analysis of the water drained from the canopy annulus of J-5 verified the presence of chlorides and sulfates.

A further contributor to the failure of the canopy seal weld could be the higher oxygen content suspected in the canopy annulus of the spares. This is due to the canopy seal welds in the spares being at high points of the system.

IV. Analysis of Event

The leakage through the canopy seal welds was insignificant. The leakage could not be quantified by the RCS mass balance performed to meet the requirements of Technical Specification 3.4.6.1. The RCS mass balance is considered to have an accuracy of 0.1 gpm. Since the leakage rate was less than 1 gpm as allowed by Technical Specification 3.4.6.1, the condition was bounded by the FSAR accident analysis.

The effect of canopy seal leaks on the structural integrity of the reactor coolant system was also reviewed. The structural integrity of the CRDM housing is maintained by the Acme-threaded fastener. The canopy seal weld does not maintain the structural integrity of the reactor coolant system. Even though ASME Section III considers the canopy seal weld a pressure boundary weld, it is not a pressure boundary as defined in the Technical Specifications.

The Technical Specifications define a pressure boundary to be leakage, except steam generator tube leakage, through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall. The definition is further clarified in the Bases for Technical Specification 3.4.6.1. The Bases state that pressure boundary leakage of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Leakage from a canopy seal weld on a CRDM is not indicative of impending gross failure since the canopy seal weld does not maintain the structural integrity of the RCS. Westinghouse reviewed this conclusion and concurred.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	8 8	—	0 0 4	—	0 0	0 6 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Another effect on the structural integrity of the reactor coolant system is the corrosion of the reactor vessel head due to boric acid. The leaks discovered during the Unit 1 second refueling outage resulted in minimal deposits of boric acid on the vessel head and there was no evidence of corrosion/wastage of the reactor head. In addition, the Unit 1 vessel head is coated with an aluminum oxide paint that provides additional protection from the corrosive nature of the boric acid.

Since leakage from the canopy seal welds was within the Technical Specification limits and does not affect the structural integrity of the reactor coolant system, the health and safety of the public were not adversely affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

The CRDM head adapter plugs at spare locations J-5, L-5, L-9, and L-11 were removed and replaced with caps welded in place. This modification constituted a permanent fix for eliminating future leakage at the above locations.

B. Corrective Actions to Prevent Recurrence:

1. Shroud inspection access doors and CRDM fan duct air sampling taps were installed in Units 1 and 2 to allow inspection of the vessel head and provide additional sampling capability. STP R-8A, "Reactor Coolant System Operational Pressure Leak Test," performed during primary system heatup and pressurization after refueling outages, has been revised to include CRDM inspection using these new inspection access doors.

2. Containment airborne particulate, containment noble gas, and the new air sample taps will be used to indicate the possible presence of canopy seal weld leaks. The Chemistry department has instituted a watchguard measures policy to detect primary coolant leaks into containment by utilizing the particulate and noble gas monitors. The Radiation Protection department has drafted a grab sample procedure to utilize the sample taps, which includes directions to notify management if significant increases in radiation levels are noted. If these three indicators show evidence of leakage, further confirmatory measures should be taken (i.e., direct or remote visual examination).

3. Canopy seal weld leaks in the CRDMs at other plants have been occurring since the early 1970s. Data on these failures has been compiled through the Westinghouse Owners Group (WOG). PG&E has been monitoring this effort and will continue to follow the WOG's findings and recommendations to insure that any corrective measures that may be applicable to DCPP are reviewed for implementation.

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VI. Additional Information

A. Failed components:

None

B. Previous LERs on similar events:

None

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