Justification For Deviations - NUREG-1431 Section 3.01.08

09-May-01

JFD Number	JFD Text	
01 Rev. A	NUREG 1431 refers to the equipment used to provide individual rod position indication as being digital, while the equipment installed and used at Point Beach for position indication of individual control rods is analog. Additionally, NUREG 1431 refers to the demand position indicators as "group step counters", while the verbiage used for these indicators at Point Beach is "bank demand step counters". Accordingly, the description of the equipment and terminology used in the proposed ITS has been alter to reflect Point Beach's design.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
	LCO 3.01.07	LCO 3.01.08
	LCO 3.01.07 COND A	LCO 3.01.08 COND A
	LCO 3.01.07 COND C RA C.1.1	LCO 3.01.08 COND C RA C.1.1
02 Rev. A	Brackets have been removed and the appropriate plant specific information has been input.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
	LCO 3.01.07 COND B RA B.1	LCO 3.01.08 COND B RA B.1

JFD Number	JFD Text	
03 Rev. A	The acceptance criteria for NUREG 1431 SR 3.1.8.1 requires the rod position indicators to agree within plus or minus 12 steps of their respective bank demand counters over the range of indicated travel. The proposed ITS will require a channel calibration to be performed for each rod position indicator. The RPIs for Point Beach indicate over the entire range of control rod travel, making the NUREG latitude of "indicated travel" unnecessary. The rod position indication system at Point Beach is an analog system which use position signals generated by linear variable differential transformers (LVDTs). The LVDTs generate an output signal proportional to actual control rod position, however, the LVDT output signal is not linear, which in effect is reflected by the variable control rod alignment limits contained in CTS 15.3.10.B.1. CTS 15.3.10.B.1 requires that rod alignment be maintained within plus or minus 24 steps of demanded position for rod positions less than or equal to 30 steps and greater than or equal to 215 steps. Demanded position in between these limits must be within plus or minus 12 steps. Based on the non-linearities inherent to the system, the CTS requirement to perform a channel calibration has been retained. By applying the definition of channel calibration to the individual rod position indicators, adjustment will be required such that the channel will respond within its "required range and accuracy" to a known input. This will allow calibration of the rod position indicators within the limitation of the equipment as currently allowed by the CTS.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
	SR 3.01.07.01	SR 3.01.08.01
04 Rev. F	The CTS requires all shutdown and control rods to be within an alignment limit which is based on reactor power. For operation > 85 percent of rated power, the limit is 12 steps with the limit becoming 24 steps for operation <= 85 percent of rated power. NUREG 1431 requires periodic verification of control rod positions when the rod position indicators are inoperable. The acceptance limits for these periodic verifications is based on a fixed alignment acceptance criteria of 12 steps. The proposed ITS Actions will require control rod alignment to be verified within the variable alignment limit of 12 steps for operation > 85 percent of rated power, and 24 steps for operation <= 85 percent of rated power. This change is necessary to retain the variable alignment limit contained in the CTS.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
	LCO 3.01.07 COND C RA C.1.2	LCO 3.01.08 COND C RA C.1.2

Justification For Deviations - NUREG-1431 Section 3.01.08

09-May-01

JFD Number	JFD Text	
05 Rev. A	Reference to the General Design Criteria (GDC) of 10 CFR 50 Appendix A has been deleted from the Bases of the Technical Specifications, substituting reference to the appropriate section of the FSAR which specifies the Point Beach design criteria. Point Beach was constructed and licensed prior to the GDC being issued. The Point Beach construction permit was issued prior to the GDCs being issued in 1971. Point Beach was designed and constructed utilizing the 1967 proposed GDCs. Accordingly, reference has been provided to the appropriate criteria and section of the Point Beach FSAR which provides explanation of Point Beach's design basis.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
06 Rev. A	The Bases for NUREG LCO 3.1.8 Required Action A.2 states that a reduction in thermal power to less than or equal to 50% power places the core into a condition where rod position does not significantly affect core peaking factors. This Bases statement then provides reference to FSAR Section [15] as the basis for this statement. Point Beach's FSAR does not state nor does it reference any analysis as a basis for this conclusion. This Technical Specifications Action is based on the qualitative evaluations concluding that a reduction in core power level establishes an acceptable trade off between core thermal output and control rod position and alignment uncertainties. As such, reference to an FSAR Section has been deleted.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
07 Rev. B	Not Used.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
08 Rev. A	The Bases has been modified to reflect the individual control rod position indications available for verification of control rod position and alignment at Point Beach. The rod position indication system at Point Beach is an analog system which provides individual control rod position indication to three separate control room readouts; analog meters, digital plasma displays, and the plant process computer. Any one of these three indicators can be used for the purpose of verifying control rod position and alignment. The position indication signal to each of these readouts is supplied by a linear variable differential transformers (LVDT) which uses the control rod drive shaft to vary the amount of magnetic coupling between primary and secondary windings of the transformer. This generates an analog output signal proportional to actual control rod position. The analog display meters and the plasma displays, provide position readouts in direct proportion to the output signal form the LVDT signal conditioning circuit. The process computer uses a fourth order polynomial to provide a more accurate control rod position readout, compensating for non-linearities in the LVDT system.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08

Justification For Deviations - NUREG-1431 Section 3.01.08

09-May-01

JFD Number	JFD Text	
09 Rev. A	Whenever an individual rod position indicator is inoperable, the Actions contained in NUREG 1431 require the position of each rod with an inoperable position indicator to be verified using the movable incore detectors once per 8 hours. Additionally, the position of each rod with an inoperable indicator must be verified within 4 hours of any rod with an inoperable indicator being moved in excess of 24 steps in one direction. Whenever an individual rod position indicator is inoperable, the CTS requires the position of each rod with an inoperable position indicator to be verified using the movable incore detectors within 8 hours. Subsequent position verifications are required once per shift and within 4 hours of any rod with an inoperable indicator being moved in excess of 24 steps in one direction using the excore detectors, thermocouples, or movable incore detectors. The proposed ITS will require the position of each rod with an inoperable position indicator to be verified using the movable incore detectors within 8 hours. Subsequent position verifications will be required every 8 hours. Subsequent verifications may be performed using other equipment (e.g. movable incore detectors, thermocouples, excore detectors, etc;) as outlined in the Bases of the ITS. In addition to these verifications, verification of position is also required within 4 hours of movement of any non-indicating rod in excess of 24 steps in one direction. This verification may also be performed using other equipment (e.g. movable incore detectors, thermocouples, excore detectors, etc;) as outlined in the Bases of the ITS. These changes are necessary to reflect the Point Beach licensing basis which allows verification of rod positions using techniques other than the movable incore detectors. Moving the equipment required to perform subsequent position verifications and verification after rod motion is addressed in Discussion of Change LA.01 of this Section.	
	ITS:	**NUREG:**
	B 3.01.07	B 3.01.08
	LCO 3.01.07 COND A RA A.1.1	LCO 3.01.08 COND A RA A.1
	LCO 3.01.07 COND A RA A.1.2	N/A
	LCO 3.01.07 COND B RA B.1	LCO 3.01.08 COND B RA B.1
10 Rev. B	Not Used.	
	ITS:	**NUREG:**
	N/A	N/A

JFD Number	JFD Text
11 Rev. A	NUREG 1431 LCO 3.1.8 Condition C, allows a single control rod demand position indicator to be inoperable on one or more rod banks. The proposed ITS will allow one or more bank demand counters to be inoperable on one or more rod banks. Control and shutdown banks A and C consist of two groups of rods each group having its own demand step counter, and control banks B and D and shutdown bank B consist of a single group and therefore, a single step counter. CTS 15.3.10.C.1.b.2, allows the demand position indication to be inoperable for one or more banks. As such, the CTS allows banks which consist of two demand counters to have both counters inoperable. Having one or both step in a bank inoperable is acceptable, based on the compensatory Actions contained in ITS Condition C in combination with the, insertion, alignment, and rod sequence requirements contained in ITS LCOs 3.1.5 and 3.1.6. Condition C Required Action C.1 requires all individual rod position indicators to be verified operable, and Required Action C.2 requires that the rods be verified to be within alignment limits. Verification of actual rod position as required by these Actions, when supplement by the Surveillance contained in proposed ITS LCOs 3.1.5 and 3.1.6, which requires rod insertion limits, control rod sequence, and control rod overlap, provided assurance that control rod position will be maintained within required limits.

ITS:	**NUREG:**
B 3.01.07	B 3.01.08
LCO 3.01.07 COND C	LCO 3.01.08 COND C

JFD Number	JFD Text
12 Rev. A	The Bases of NUREG 1431 LCO 3.1.8 contains a discussion related to the operability of the individual control rod position indicator and bank demand step counters. This Section has been modified to reflect the Point Beach design as follows: The individual rod position indicators should be considered operable based on the indicators being satisfactorily calibrated. Agreement of individual rod position indication with the bank demand indicators, while required to verify alignment limits and as an input into confirming acceptable operation of the rod position indicator, is not a criteria for individual rod position indicator operability. Disagreement between these indicators can be indicative of an actual misalignment, or stuck rod. It is inappropriate to consider the individual rod position indicators inoperable, but rather the reason for disagreement investigated, and the appropriate action taken based on the cause of the disagreement. Failed coils is a criteria for digital systems, as any failed coil in an analog system will result in complete failure of the indicator. The bank demand indicators should not be calibrated solely on information from the individual rod position indicators. Doing so could invalidate the basis for the alignment criteria established in the rod alignment LCO. Calibration of the bank demand counter is accomplished through a simple agreement verification between demanded position and actual rod position. Actual position can be determined through numerous means, from a known fully inserted or withdrawn position, or flux mapping. The methods for establishing agreement between demanded position and actual rod position are details which have been addressed procedurally by the licensee, which are not required in the LCO Bases section. **ITS:** B 3.01.07 **NUREG:** B 3.01.08

JFD Number	JFD Text
13 Rev. A	NUREG 1431 LCO 3.1.8 Condition A, allows one control rod position indicator to be inoperable on one or more rod groups. The proposed ITS will allow one or more rod position indicators to be inoperable on one or more rod groups. CTS 15.3.10.C.1.a, allows one or more rod position indicators to be inoperable. As such, the CTS will allow multiple rod position indicators in the same group to be inoperable. Multiple rod position indicators in the same group inoperable is acceptable, based on the compensatory Actions contained in proposed ITS Conditions A and B which require verification of control rod positions periodically and after significant motion. Verification of actual rod position as required by these Actions, when supplemented by the Surveillance contained in proposed ITS LCOs 3.1.5 and 3.1.6, which requires rod insertion limits, control rod sequence, and control rod overlap, provided assurance that control rod position will be maintained within required limits. As such, the CTS provision which allows multiple control rod position indicators to be inoperable in the same groups has been retained. Approved TSTF 234, Revision 1 has not been incorporated into the proposed ITS. Incorporation of TSTF 234 would not be in accordance with the current licensing basis for PBNP, which provides for one or more inoperable rod position indicators. **ITS:** B 3.01.07; LCO 3.01.07 COND A **NUREG:** B 3.01.08; LCO 3.01.08 COND A
14 Rev. F	CTS provides an allowance of a one hour soak prior to verifying rod operability and alignment limits. This time period is based on the time deemed necessary to allow the control rod drive shaft to reach thermal equilibrium. This change incorporates the current licensing basis (CLB) provisions of TSCR 216 and is therefore administrative. **ITS:** LCO 3.01.07 NOTE 2 **NUREG:** N/A

Approved TSTF 136 7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued) 11 or more bank	B.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
C. One demand position indicator (s) per bank inoperable for one or more banks.	C.1.1 Verify by administrative means all 1 ~~[D]~~ RPIs for the affected banks are OPERABLE.	Once per 8 hours
	AND	
4 Verify the most withdrawn rod and the least withdrawn rod of the affected banks are: ≤ 12 steps apart when RTP is > 85 percent, and ≤ 24 steps apart when RTP is ≤ 85 percent.	C.1.2 ~~Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart.~~	Once per 8 hours
	OR	
	C.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours

B RAI 3.1.8-1

F TSCR 216

LCO 3.1.8 Inserts

Insert 3.1.8-01:

	AND A.1.2 Verify the position of the rods with inoperable position indicators.	Once per 8 hours

BASES

ACTIONS (continued)

9

Insert B 3.1.8-5

9

A.1.2

~~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.~~

Insert B 3.1.8-6

Approved TSTF 136

A.2

9

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)~~. 6

B RAI 3.1.8-1

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~~ Actions A.1.1 and A.1.2 above.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of ~~A.1 and A.2~~ A.1.1, A.1.2, and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

2

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the ~~rod positions~~. 2

11

C.1.1 and C.1.2

or more (s) 1

F TSCR 216

With one or more demand position indicator(s) per bank inoperable, the rod positions can be determined by the ~~D~~RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod

Approved TSTF 136

LCO 3.1.8 BASES INSERTS

Insert B 3.1.8-1:

This surveillance is performed prior to reactor criticality after each removal of the reactor head as there is potential for unnecessary plant transients if the SR were performed with the reactor at power.

Insert B 3.1.8-2:

The individual rod position indication system consists of three separate control room readouts; analog meters, digital displays, and the plant process computer. The position indication signal to each of these readouts is supplied by a linear variable differential transmitter (LVDT) which uses the control rod drive shaft to vary the amount of magnetic coupling between primary and secondary windings of the transformer. This generates an analog output signal proportional to actual control rod position. The analog display meters and the digital displays, provide position readouts in direct proportion to the output signal from the LVDT signal conditioning circuit. The process computer applies a polynomial to compensate for non-linearities in the LVDT system, providing for a more accurate position readout. Any one of these three readouts can be used for the purpose of verifying control rod position and alignment. The RPI system has an indication accuracy of 5% of span (11.5 steps); therefore, the maximum deviation between actual and demanded indication could be 24 steps or approximately 15 inches.

Insert B 3.1.8-3:

LCO

LCO 3.1.7 specifies that one RPI System and one Bank Demand Position Indication System be OPERABLE for each control rod.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

The comparison of bank demand position and RPI System may take place at any time up to one hour after rod motion, at any power level. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach a thermal equilibrium and thus present a consistent position

F

TSCR 216

indication. A similar time period (up to one hour after rod motion) is allowed for comparison of the bank insertion limits and the RPI System. Based on this allowance, position indication may be considered OPERABLE during the thermal soak time to allow for position indication to stabilize.

F TSCR 216

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

Insert B 3.1.8-4:

By determining the non-indicating rod's position initially through use of the incore movable detectors, actual rod position is established with a high degree of certainty.

Insert B 3.1.8-5:

When one or more RPI channel(s) per group fails, the position of the rod can still be determined by use of the incore movable detectors (the incore is not effective for determining rod position until the power level is above approximately 5% RTP). By determining the non-indicating rod's position initially through use of the incore movable detectors, actual rod position is established with a high degree of certainty. Initial verification of RCCA position within the Completion Time of 8 hours is adequate for continued power operation above 50% of RTP, based on meeting the alignment requirements for the controls rod(s) prior to the individual position indicator becoming inoperable and the probability of a control rod becoming significantly out of position coincident with an event sensitive to that rod position is small.

B RAI 3.1.8-2

Insert B 3.1.8-6:

After the initial position determination performed in Required Action A.1.1 above, Required Action A.1.2 requires periodic position verifications for control rods with inoperable individual position indicators once every 8 hours. Position verification can be performed by use of thermocouples, excore instrumentation, or the movable incore detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, Required Action B.1 below is required. Therefore, verification of RCCA position once every 8 hours is adequate for allowing continued power operation above 50% of RTP, since the probability of undetected rod misalignment and an event sensitive to that rod position is small.

LCO 3.1.8 BASES INSERTS

Insert B 3.1.8-7:

A CHANNEL CALIBRATION of the individual rod position indicators is performed to ensure that the rod position indicators respond within the necessary range and accuracy.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 Individual control rod position indication and bank demand indication shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

B
RAI 3.1.8-2

ACTIONS

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

F
Correction

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RPI(s) per group inoperable for one or more groups.	A.1.1 Verify the position of the rods with inoperable position indicators by using movable incore detectors.	8 hours
	AND	
	A.1.2 Verify the position of the rods with inoperable position indicators.	Once per 8 hours
	OR	
	A.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

B
RAI 3.1.8-1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	B.1 Verify the position of the rods with inoperable position indicators. OR B.2 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours 8 hours
C. One or more bank demand position indicator(s) per bank inoperable for one or more banks.	C.1.1 Verify by administrative means all RPIs for the affected banks are OPERABLE. AND C.1.2 Verify the most withdrawn rod and the least withdrawn rod of the affected banks are: ≤ 12 steps apart when RTP is > 85 percent, and ≤ 24 steps apart when RTP is ≤ 85 percent. OR C.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours Once per 8 hours 8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours

B
RAI 3.1.8-1

F
TSCR 216

BASES

LCO

LCO 3.1.7 specifies that one RPI System and one Bank Demand Position Indication System be OPERABLE for each control rod.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

The comparison of bank demand position and RPI System may take place at any time up to one hour after rod motion, at any power level. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach a thermal equilibrium and thus present a consistent position indication. A similar time period (up to one hour after rod motion) is allowed for comparison of the bank insertion limits and the RPI System. Based on this allowance, position indication may be considered OPERABLE during the thermal soak time to allow for position indication to stabilize. F TSCR 216

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

APPLICABILITY

The requirements on the RPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System. B RAI 3.1.8-2

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

B RAI 3.1.8-1

BASES

ACTIONS (continued)

A.1.1

When one or more RPI channel(s) per group fails, the position of the rod can still be determined by use of the incore movable detectors (the incore is not effective for determining rod position until the power level is above approximately 5% RTP). By determining the non-indicating rod's position initially through use of the incore movable detectors, actual rod position is established with a high degree of certainty. Initial verification of RCCA position within the Completion Time of 8 hours is adequate for continued power operation above 50% of RTP, based on meeting the alignment requirements for the controls rod(s) prior to the individual position indicator becoming inoperable and the probability of a control rod becoming significantly out of position coincident with an event sensitive to that rod position is small. B RAI 3.1.8-2

A.1.2 B RAI 3.1.8-1

After the initial position determination performed in Required Action A.1.1 above, Required Action A.1.2 requires periodic position verifications for control rods with inoperable individual position indicators once every 8 hours. Position verification can be performed by use of thermocouples, excore instrumentation, or the movable incore detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, Required Action B.1 below is required. Therefore, verification of RCCA position once every 8 hours is adequate for allowing continued power operation above 50% of RTP, since the probability of undetected rod misalignment 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. B RAI 3.1.8-1

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 Actions A.1.1 and A.1.2 above.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1.1, A.1.2 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods

ACTIONS (continued)

are still properly positioned, relative to their group positions.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

B
RAI 3.1.8-1

C.1.1 and C.1.2

With one or more demand position indicator(s) per bank inoperable, the rod positions can be determined by the RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are: ≤ 12 steps apart when RTP is > 85 percent, and ≤ 24 steps apart when RTP is ≤ 85 percent within the allowed Completion Time of once every 8 hours is adequate.

F
TSCR 216

C.2

B
RAI 3.1.8-1

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

A CHANNEL CALIBRATION of the individual rod position indicators is performed to ensure that the rod position indicators respond within the necessary range and accuracy.

SURVEILLANCE REQUIREMENTS (continued)	This surveillance is performed prior to reactor criticality after each removal of the reactor head as there is potential for unnecessary plant transients if the SR were performed with the reactor at power.
REFERENCES	1. FSAR. Section 7.1.2. 2. FSAR. Chapter 14.

< See Section 3.1 >

A.1

15.3.10 CONTROL ROD AND POWER DISTRIBUTION LIMITS

A.5

Applicability

Applies to the operation of the control rods and to core power distribution limits.

< See Section 3.1 >

Objective

~~To insure~~ (1) core subcriticality after a reactor trip, (2) a limit on potential reactivity insertions from a hypothetical rod cluster control assembly (RCCA) ejection, and (3) an ~~acceptable~~ core power distribution ~~during~~ power operation.

A.6

Specification

A. SHUTDOWN MARGIN

1. The shutdown margin shall exceed the applicable value as shown in Figure 15.3.10-2 under all steady-state operating conditions from 350^{o}F to full power. If the shutdown margin is less than the applicable value of Figure 15.3.10-2, within 15 minutes initiate boration to restore the shutdown margin.

2. A shutdown margin of at least 1% $\Delta k/k$ shall be maintained when the reactor coolant temperature is less than 350^{o}F. If the shutdown margin is less than this limit, within 15 minutes initiate boration to restore the shutdown margin.

B. ROD OPERABILITY AND BANK ALIGNMENT LIMITS

NOTE: One hour is allowed following rod motion prior to verifying rod operability and bank alignment limits.

1. During power and low power operation, all shutdown and control rods shall be operable and positioned within the allowed rod misalignment between the individual indicated rod positions and the bank demand position as follows;

< See LCO 3.1.5 >

F
TSCR 216

i) For operation ≤ 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±24 steps.
ii) For operation > 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±12 steps.

If an RCCA does not step in upon demand, up to six hours is allowed to determine whether the problem with stepping is an electrical problem. If the problem cannot be resolved within six hours, the RCCA shall be declared inoperable until it has been verified that it will step in or would drop upon demand.

F
TSCR 216

< See LCO 3.1.6 and 3.1.7 >

AND

b. Within two hours fully withdraw the shutdown banks.

c. If the above actions and associated completion times are not met, be in hot shutdown within the following six hours.

2. When the reactor is critical, the control banks shall be inserted no further than the limits shown by the lines on Figure 15.3.10-1. If this condition is not met, perform the following actions:

a. Within one hour verify that the shutdown margin exceeds the applicable value as shown in Figure 15.3.10-2; OR within one hour restore the shutdown margin by boration;
AND

b. Within two hours restore the control banks to within limits.

c. If the above actions and associated completion times are not met, be in hot shutdown within the following six hours.

L.1

Clarify Mode of Applicability to be Mode 1

E. POWER DISTRIBUTION LIMITS

< See LCO 3.2.2 >

L.4

1. Hot Channel Factors

LA.1

be within the limits specified in the COLR.

as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$.

a. The hot channel factors ~~defined in the basis~~ shall meet the following limits:

	For OFA and Upgraded Fuel	~~For 422V+ Fuel~~
for P > 0.5	~~$F_Q(Z) \le (2.50)/P \times K(Z)$~~	~~$F_Q(Z) \le (2.60)/P \times K(Z)$~~
for P ≤ 0.5	~~$F_Q(Z) \le 5.00 \times K(Z)$~~	~~$F_Q(Z) \le 5.20 \times K(Z)$~~
	$F^N_{\Delta H} < 1.70 \times [1 + 0.3(1-P)]$	$F^N_{\Delta H} < 1.77 \times [1 + 0.3(1-P)]$

B
Amendment 193/198

LA.1

Where P is the fraction of full power at which the ~~core is operating~~, K(Z) is the function in Figure 15.3.10-3 ~~or Figure 15.3.10-3a~~, as applicable, and Z is ~~the core height~~ location of F_Q.

Cond A - RA A.1

b. If ~~$F_Q(Z)$~~ exceeds the limit of Specification 15.3.10.E.1.a, within ~~fifteen minutes~~ reduce thermal power ~~until $F_Q(Z)$ limits are satisfied~~

$F_Q^C(Z)$

L.4

~~(1) After thermal power has been reduced in accordance with Specification 15.3.10.E.1.b, perform the following actions:~~

A.2

> 1% RTP for each 1% $F_Q^C(Z)$ exceeds it limit

M.1

B
Amendment 193/198

Cond A - RA A.2

Reduce Power Range Neutron Flux – High trip setpoints ≥ 1% for each 1% $F^C_Q(Z)$ exceeds limit.

L.2 → 72 hours

A.1

(a) Within ~~eight~~ hours ~~reduce the full power Power Range Neutron Flux - High trip setpoints by an amount equivalent to the power reduction required in Specification 15.3.10.E.1.b;~~
AND

M.2

≥ 1% for each 1% $F^C_Q(Z)$ exceeds limit.

(b) Within 72 hours reduce Overpower ~~and Overtemperature~~ ΔT trip setpoints ~~by an amount equivalent to the power reduction required in Specification 15.3.10.E.1.b;~~
AND

L.3

F TSCR 216

Cond A - RA A.3

(c) Verify that $F_Q(Z)$ will be within limits for the increased power level prior to increasing any setpoints that have been reduced and thermal power above the limit specified in Specification 15.3.10.E.1.b.

and $F^W_Q(Z)$

Cond A - Note and RA A.4 Completion Time

A.3

(d) If the above actions and associated completion times are not met, be ~~in low power operation~~ within the following six hours.

Mode 2 ← L.1/L.5

L.4

Cond C and RA C.1

c. If $F^N_{\Delta H}$ exceeds the limit of Specification 15.3.10.E.1.a, within four hours reduce thermal power to restore $F^N_{\Delta H}$ to within limits OR perform the following actions:

(1) Within four hours reduce thermal power to ≤50 percent rated thermal power;
AND

(2) Within eight hours reduce the full power Power Range Neutron Flux - High trip setpoints to ≤58 percent rated thermal power.

In addition to the above actions, the following actions shall also be performed during the subsequent power escalation if $F^N_{\Delta H}$ had exceeded the limit of Specification 15.3.10.E.1.a:

(3) Verify that $F^N_{\Delta H}$ is within limits within 24 hours;
AND

(4) Verify that $F^N_{\Delta H}$ is within limits prior to thermal power exceeding 50 percent of rated thermal power;
AND

(5) Verify that $F^N_{\Delta H}$ is within limits prior to thermal power exceeding 75 percent of rated thermal power;
AND

(6) Verify that $F^N_{\Delta H}$ is within limits within 24 hours after reaching ≥95 percent of rated thermal power.

Insert new Condition B, Note, and Required Action B.1 – B.4 $F^W_Q(Z)$ not within limit

L.4

< See LCO 3.2.2 >

< See LCO 3.1.8 >

increased surveillance of the core if one or more rod position indicator channels is out-of-service serves to guard against any significant loss in shutdown margin or margin to core thermal limits.

The history of malpositioned RCCA's indicates that in nearly all such cases, the malpositioning occurred during bank movement. Checking rod position after bank motion exceeds 24 steps will verify that the RCCA with the inoperable LVDT is moving properly with its bank and the bank step counter. Malpositioning of an RCCA in a stationary bank is very rare, and if it does occur, it is usually gross slippage which will be seen by external detectors. Should it go undetected, the time between the rod position checks performed every shift is short with respect to the probability of occurrence of another independent undetected situation which would further reduce the shutdown capability of the rods.

Any combination of misaligned rods below 10% rated power will not exceed the design limits. For this reason, it is not necessary to check the position of rods with inoperable LVDTs below 10% power; plus, the incore instrumentation is not effective for determining rod position until the power level is above approximately 5%.

A.4

Power Distribution

During power operation, the global power distribution is limited by TS 15.3.10.E.2, "Axial Flux Difference," and TS 15.3.10.E.3, "Quadrant Power Tilt," which are directly and continuously measured process variables. These specifications, along with TS 15.3.10.D, "Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

As a result of the increased peaking factors allowed by the new 422V+ fuel, a new column was added to TS 15.3.10.E.1.a. The full power $F^N_{\Delta H}$ peaking factor design limit (radial peaking factor) for 422V+ fuel will increase to 1.77 from the 1.70 value for the OFA fuel. The maximum $F_Q(Z)$ peaking factor limit (total peaking factor) for 422V+ fuel will increase to 2.60 from the 2.50 value for the OFA fuel. The OFA fuel design will retain the current $F^N_{\Delta H}$ and $F_Q(Z)$ peaking factors of 1.70 and 2.50, respectively. In addition, the K(Z) envelope for the new 422V+ fuel was modified and a new TS figure 15.3.10-3a was developed and inserted in the Technical Specifications. The K(Z) envelope in TS Figure 15.3.10-3 remains for the OFA fuel.

B
Amend
193/198

The purpose of the limits on the values of $F_Q(Z)$, the height dependent heat flux hot channel factor, is to limit the local peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution. $F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

F
TSCR
216

< See LCO 3.2.2 >

The purpose of the limits on $F^N_{\Delta H}$, the nuclear enthalpy rise hot channel factor, is to ensure that the fuel design criteria are not exceded and the accident analysis assumptions remain valid. The design limits on local and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along a fuel rod to the average fuel rod power. Imposed limits pertain to the maximum $F^N_{\Delta H}$ in the core, that is the fuel rod with the highest integrated power. It should be noted that $F^N_{\Delta H}$ is based on an integral and is used as such in the DNB calculations. Local heat flux is obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal (x-y) power shapes throughout the core. Thus, the horizontal power shape at the point of maximum heat flux is not necessarily directly related to $F^N_{\Delta H}$.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least monthly. However, during power operation, the global power distribution is monitored by TS 15.3.10.E.2, "Axial Flux Difference," and TS 15.3.10.E.3, "Quadrant Power Tilt," which address directly and continuously measured process variables.

It has been determined that, provided the following conditions are observed, the hot channel factor limits will be met: A.4

1. Control rods in a single bank move together with no individual rod insertion differing by more than 24 steps from the bank demand position (operation at greater than 85 percent of rated power), nor more than 36 steps (operation at less than or equal to 85 percent of rated power). An indicated misalignment limit of 12 steps precludes a rod misalignment of greater than 24 steps with consideration of instrumentation error; 24 steps indicated misalignment corresponds to 36 steps with instrumentation error. F TSCR 216

2. Control rod banks are sequenced with overlapping banks as described in Figure 15.3.10-1.

3. Control bank insertion limits are not violated.

4. Axial power distribution control procedures, which are given in terms of flux difference control and control bank insertion limits, are observed. Flux difference refers to the difference in signals between the top and bottom halves of two-section excore neutron detectors. The flux difference is a measure of the axial offset which is defined as the difference in normalized power between the top and bottom halves of the core.

F TSCR 216

< See LCO 3.2.2 >

The permitted relaxation of $F^N_{\Delta H}$ allows radial power shape changes with rod insertion to the insertion limits. It has been determined that provided the above four conditions are observed, these hot channel factor limits are met. In Specification 15.3.10.E.1.a, F_Q is arbitrarily limited for $p \leq 0.5$.

The upper bound envelope F_Q (defined in 15.3.10.E) times the normalized peaking factor axial dependence of Figure 15.3.10-3 for OFA and Upgraded OFA Fuel and Figure 15.3.10-3a for 422V+ Fuel (consistent with the Technical Specifications on power distribution control as given in Section 15.3.10) was used in the large and small break LOCA analyses. The envelope was determined based on allowable power density distributions at full power restricted to axial flux difference (ΔI) values consistent with those in Specification 15.3.10.E.2. B Amend 193/198

The results of the analyses based on this upper bound envelope indicate a peak clad temperature of less than the 2200°F limit. When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be taken into account. Five percent is the appropriate allowance for a full core map taken with the moveable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. A.4

In the design limit of $F^N_{\Delta H}$, there is eight percent allowance for uncertainties which means that normal operation of the core is expected to result in a design $F^N_{\Delta H} \leq 1.70/1.08$. The logic behind the larger uncertainty in this case is as follows:

(a) Normal perturbations in the radial power shape (i.e., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q.

(b) While the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired value, he has no direct control over $F^N_{\Delta H}$.

(c) An error in the predictions for radial power shape which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control; but compensation for $F^N_{\Delta H}$ is less readily available.

Measurements of the hot channel factors are required as part of startup physics tests, at least each full power month operation, and whenever abnormal power distribution conditions require a reduction of core power to a level based upon measured hot channel factors. The incore map taken following initial loading provides confirmation of the basic nuclear design bases including proper fuel loading patterns. The periodic monthly incore mapping provides additional assurance that the nuclear design bases remain inviolate and identify operational anomalies which would, otherwise, affect these bases.

The measured hot channel factors are increased as follows:

(a) The measurement of total peaking factor, F_Q^{meas}, shall be increased by three percent to account for manufacturing tolerance and further increased by five percent to account for measurement error.

F TSCR 216

FIGURE 15.3.10-3

POINT BEACH UNITS 1 AND 2

HOT CHANNEL FACTOR NORMALIZED OPERATING ENVELOPE

LA.1

Moved to COLR

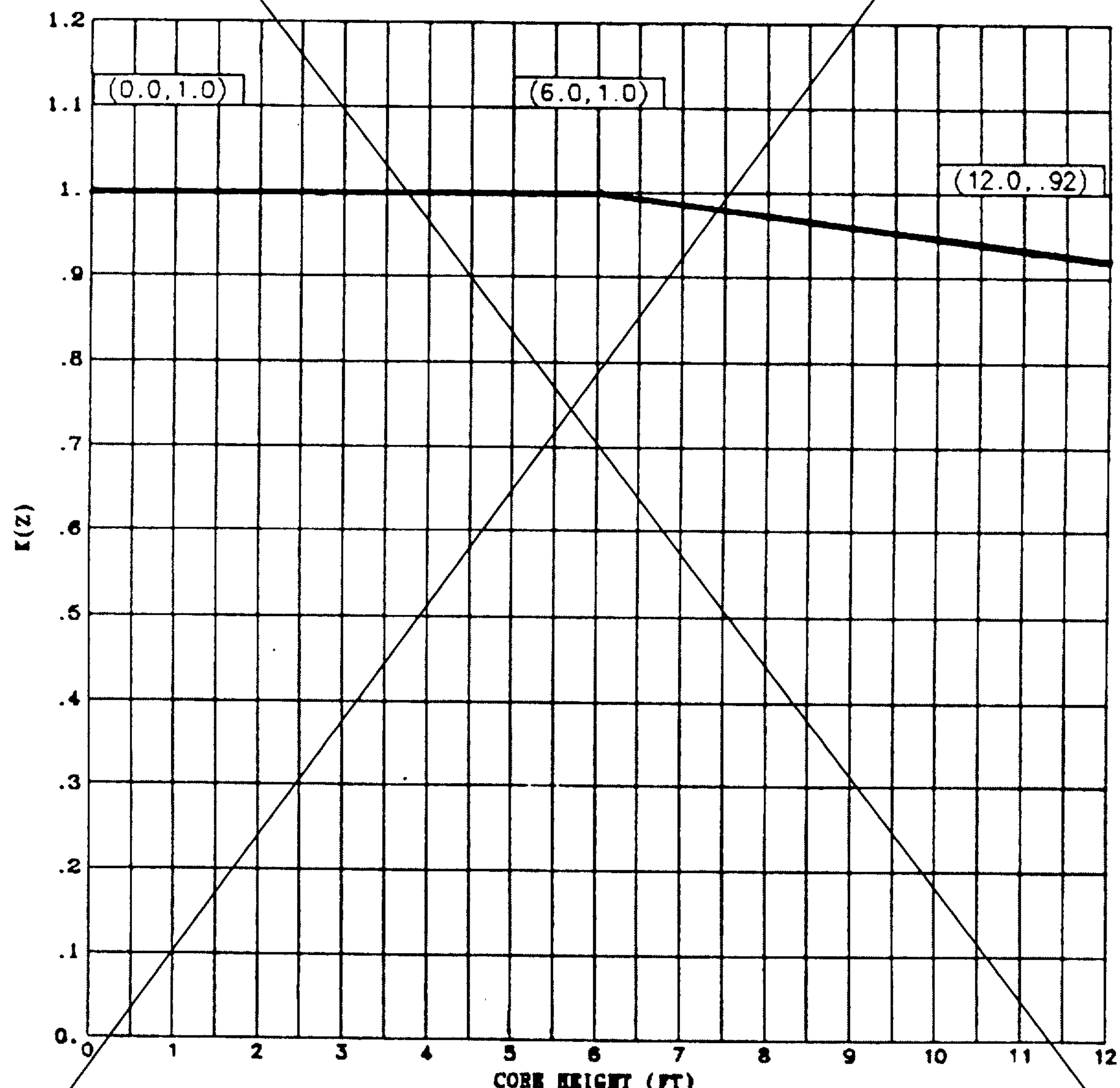


TABLE 15.4.1-2 (Continued)

30.	Pressurizer Heaters	Verify that 100 KW of < See Section 3.4 >	Quarterly
31.	CVCS Charging Pumps	Verify operability < See LCO 3.5.2 >	Quarterly
32.	Potential Dilution in Progress Alarm	Verify operability of < See Section 3.3 >	Prior to placing plant in cold shutdown.
33.	~~Core Power Distribution~~ < See LCOs: 3.3.2, 3.4.16, 3.5.4, 3.7.18, and 3.4.13 >	~~Perform power distribution maps using movable incore detector system to confirm hot channel factors.~~ LA.2	~~Monthly (20)~~ See Insert 3.2.1-2
34.	Shutdown Margin	Perform shutdown margin < See Section 3.1 >	Daily (21)

(1) Required only during periods of power operation.

(2) Q determination will be started when the gross activity analysis of a filtered sample indicates ³10mCi/cc and will be redetermined if the primary coolant gross radioactivity of a filtered sample increases by more than 10mCi/cc. < See Section 3.4 >

(3) Drop test shall be conducted at rated reactor coolant flow. Rods shall be dropped under both cold and hot condition, but cold drop tests need not be timed. < See LCO 3.1.5 >

(4) Drop tests will be conducted in the hot condition for rods on which maintenance was performed.

(5) As accessible without disassembly of rotor.

(6) Not required during periods of refueling shutdown.

(7) At least once per week during periods of refueling shutdown.

(8) At least three times per week (with maximum time of 72 hours between < See LCO 3.4.16 > refueling shutdown.

(9) Not required during periods of cold or refueling shutdown, but m < See LCOs 3.3.1, 3.6.3 > been performed during the previous surveillance period.

(10) Sample to be taken after a minimum of 2 EFPD and 20 days power operation since the reactor was last subcritical for 48 hours or longer. < See LCO 3.4.16 >

(11) An approximately equal number of valves shall be tested each refueling outage such that all valves will be tested within a five year period. If any valve fails its tests, an additiona < See LCOs 3.7.1, 3.4.10 > originally tested shall be tested. If any of the additional tested valves fail, all remaining valves shall be tested.

(12) The specified buses shall be determined energized in the required manner at least once per shift by verifying correct static transfer switch alignment and indicated voltag < See Section 3.8 >

(13) Not required if the block valve is shut to isolate a PORV that is inoperable for reasons other than excessive seat leakage. < See LCO 3.4.11 >

(14) Only applicable when the overpressure mitigation system is in service.

(15) Required to be performed only if conditions will be established, as defined in Spec < See LCO 3.4.12 > where the PORVs are used for low temperature overpressure protection. The test must be performed prior to establishing these conditions.

Associated Specification removed with Unit 1 Amendment 176 and Unit 2 Amendment 180

< See LCO 3.4.12 >

TABLE 15.4.1-2 (Continued)

A.1

(16) Test valve operation in accordance with the inservice test requirements of the ASME Boiler and Pressure Vessel Code, Section XI.

(17) Operability of charging pumps is verified by ensuring that the pumps develop the required flowrate, as specified by the In-Service Test Program.

(18) Not required to be performed if the reactor is subcritical.

(19) Required only when the BAST(s) are relied upon as a source of borated water.

(20) Perform during power operation at effective full power monthly intervals. Following a refueling shutdown, a power distribution map shall be performed prior to exceeding 90% of rated thermal power.

(21) Only applicable during low-power physics testing.

Replace with Insert 3.2.1-2

< See LCO 3.5.2 >

< See LCO 3.1.1 and 3.1.10>

< See LCO 3.1.5 >

CTS INSERTS

INSERT 3.2.1-1:

CONDITION	REQUIRED ACTION		COMPLETION TIME
--------NOTE-------- Required Action B.4 shall be completed whenever this condition is entered. -------------------- B. $F_Q^W(Z)$ not within limits.	B.1	Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	<u>AND</u> B.2	Reduce Power Range Neutron Flux-High trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u> B.3	Reduce Overpower T trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u> B.4	Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits.

L.4

INSERT 3.2.1-2:

SURVEILLANCE REQUIREMENTS

---NOTE---
During power escalation at the beginning of each cycle, THERMAL POWER may be increased until an equilibrium power level has been achieved, at which a power distribution map is obtained.

M.3

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify $F_Q^C(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP AND Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified AND 31 EFPD thereafter

L.4

(continued)

A.1

CTS INSERTS

INSERT 3.2.1-2 (continued):

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	------------------NOTE------------------ If $F_Q^W(Z)$ measurements indicate $$\text{maximum over } z \left[\frac{F_Q^C(Z)}{K(Z)} \right]$$ has increased since the previous evaluation of $F_Q^C(Z)$: a. Increase $F_Q^W(Z)$ by the greater of a factor of 1.02 or by an appropriate factor specified in the COLR and reverify $F_Q^W(Z)$ is within limits; or b. Repeat SR 3.2.1.2 once per 7 EFPD until two successive flux maps indicate that the $$\text{maximum over } z \left[\frac{F_Q^C(Z)}{K(Z)} \right]$$ has not increased. --- Verify $F_Q^W(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP AND Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^W(Z)$ was last verified AND 31 EFPD thereafter

L.4

M.3

A.1

< See Section 3.1 >

A.1

15.3.10 CONTROL ROD AND POWER DISTRIBUTION LIMITS

Applicability

Applies to the operation of the control rods and to core power distribution limits. A.2

< See Section 3.1 >

Objective

~~To insure~~ (1) core subcriticality after a reactor trip, (2) a limit on potential reactivity insertions from a hypothetical rod cluster control assembly (RCCA) ejection, and (3) an ~~acceptable~~ core power distribution ~~during~~ power operation. A.3

Specification

A. SHUTDOWN MARGIN

1. The shutdown margin shall exceed the applicable value as shown in Figure 15.3.10-2 under all steady-state operating conditions from 350°F to full power. If the shutdown margin is less than the applicable value of Figure 15.3.10-2, within 15 minutes initiate boration to restore the shutdown margin.

2. A shutdown margin of at least 1% $\Delta k/k$ shall be maintained when the reactor coolant temperature is less than 350°F. If the shutdown margin is less than this limit, within 15 minutes initiate boration to restore the shutdown margin.

B. ROD OPERABILITY AND BANK ALIGNMENT LIMITS

NOTE: One hour is allowed following rod motion prior to verifying rod operability and bank alignment limits.

1. During power and low power operation, all shutdown and control rods shall be operable and positioned within the allowed rod misalignment between the individual indicated rod positions and the bank demand position as follows;

   i) For operation ≤ 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±24 steps.

   ii) For operation > 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±12 steps.

   If an RCCA does not step in upon demand, up to six hours is allowed to determine whether the problem with stepping is an electrical problem. If the problem cannot be resolved within six hours, the RCCA shall be declared inoperable until it has been verified that it will step in or would drop upon demand.

F TSCR 216

< See Section 3.1 >

F TSCR 216

< See LCO 3.1.6/7 >

A.1

AND

b. Within two hours fully withdraw the shutdown banks.

c. If the above actions and associated completion times are not met, be in hot shutdown within the following six hours.

2. When the reactor is critical, the control banks shall be inserted no further than the limits shown by the lines on Figure 15.3.10-1. If this condition is not met, perform the following actions:

L.3

Clarify Mode of Applicability to be Mode 1

a. Within one hour verify that the shutdown margin exceeds the applicable value as shown in Figure 15.3.10-2; OR within one hour restore the shutdown margin by boration;

AND

b. Within two hours restore the control banks to within limits.

c. If the above actions and associated completion times are not met, be in hot shutdown within the following six hours.

E. POWER DISTRIBUTION LIMITS

1. Hot Channel Factors

LA.1

be within the limits specified in the COLR.

a. The hot channel factors ~~defined in the basis~~ shall ~~meet the following limits~~:

< See LCO 3.2.1 >

$$F_Q(Z) \leq \frac{(2.50)}{P} \times K(Z) \qquad for\ P > 0.5$$

$$F_Q(Z) \leq 5.00 \times K(Z) \qquad for\ P \leq 0.5$$

$$\cancel{F^N_{\Delta H} < 1.70 \times [1 + 0.3\,(1-P)]}$$

LA.1

Moved to COLR

~~Where P is the fraction of full power at which the core is operating.~~ K(Z) is the function in Figure 15.3.10-3 and Z is the core height location of F_Q.

b. If $F_Q(Z)$ exceeds the limit of Specification 15.3.10.E.1.a, within fifteen minutes reduce thermal power until $F_Q(Z)$ limits are satisfied;

(1) After thermal power has been reduced in accordance with Specification 15.3.10.E.1.b, perform the following actions:

< See LCO 3.2.1 >

A.1

(a) Within eight hours reduce the full power Power Range Neutron Flux - High trip setpoints by an amount equivalent to the power reduction required in Specification 15.3.10.E.1.b;
AND

(b) Within 72 hours reduce Overpower and Overtemperature ΔT trip setpoints by an amount equivalent to the power reduction required in Specification 15.3.10.E.1.b;
AND

(c) Verify that $F_Q(Z)$ will be within limits for the increased power level prior to increasing any setpoints that have been reduced and thermal power above the limit specified in Specification 15.3.10.E.1.b.

(d) If the above actions and associated completion times are not met, be in low power operation within the following six hours.

COND A RA A.1.1

c. If $F^N_{\Delta H}$ exceeds the limit of Specification 15.3.10.E.1.a, within four hours ~~reduce thermal power to~~ restore $F^N_{\Delta H}$ to within limits OR perform the following actions: L.1

COND A RA A.1.2.1

(1) Within four hours reduce thermal power to ≤50 percent rated thermal power;
AND

72 L.2

COND A RA A.1.2.2

(2) Within ~~eight~~ hours reduce the full power Power Range Neutron Flux - High trip setpoints to ~~≤58~~ percent rated thermal power.

55 M.3

A.4 COND A NOTE

In addition to the above actions, the following actions ~~shall~~ also be performed ~~during the subsequent power escalation~~ if $F^N_{\Delta H}$ had exceeded ~~the~~ limit of Specification 15.3.10.E.1.a: M.1

COND A RA A.2

(3) Verify that $F^N_{\Delta H}$ is within limits within 24 hours;
AND

COND A RA A.3

(4) Verify that $F^N_{\Delta H}$ is within limits prior to thermal power exceeding 50 percent of rated thermal power;
AND

(5) Verify that $F^N_{\Delta H}$ is within limits prior to thermal power exceeding 75 percent of rated thermal power;
AND

A.4 COND A RA A.3 NOTE

(6) Verify that $F^N_{\Delta H}$ is within limits within 24 hours after reaching ≥95 percent of rated thermal power.

< See LCO 3.2.1 >

COND A
RA A.3

(7) If the above actions and associated completion times are not met, be in ~~hot shutdown~~ within the following six hours.

MODE 2 L.3

< See LCO 3.2.3 >

2. Axial Flux Difference

NOTE: The axial flux difference shall be considered outside limits when two or more operable excore channels indicate that axial flux difference is outside limits.

a. During power operation with thermal power ≥50 percent of rated thermal power, the axial flux difference shall be maintained within the limits specified in Figure 15.3.10-4.

(1) If the axial flux difference is not within limits, within 15 minutes restore to within limits. If this action and associated completion time is not met, perform the following actions:

(a) Reduce thermal power until the axial flux difference is within limits;
OR
(b) Within three hours reduce thermal power to ≤50 percent of rated thermal power.

b. If it is necessary to restrict thermal power to ≤50 percent of rated thermal power, within the next four hours reduce the Power Range Neutron Flux - High Trip setpoints to ≤55 percent.

c. If the alarms used to monitor the axial flux difference are rendered inoperable, verify that the axial flux difference is within limits for each operable excore channel once within one hour and every hour thereafter.

3. Quadrant Power Tilt

a. During power operation with thermal power greater than 50 percent of rated thermal power, the indicated quadrant power tilt shall not exceed 2 percent. If this condition is not met, perform the following actions:

(1) Within two hours, reduce thermal power ≥2 percent from rated thermal power for each 1 percent of indicated quadrant power tilt;
AND
(2) Within 24 hours and once per seven days thereafter, verify that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the limits of Specification 15.3.10.E.1.a;
AND

< See LCO 3.2.4 >

< See LCO 3.1.8 >

increased surveillance of the core if one or more rod position indicator channels is out-of-service serves to guard against any significant loss in shutdown margin or margin to core thermal limits.

The history of malpositioned RCCA's indicates that in nearly all such cases, the malpositioning occurred during bank movement. Checking rod position after bank motion exceeds 24 steps will verify that the RCCA with the inoperable LVDT is moving properly with its bank and the bank step counter. Malpositioning of an RCCA in a stationary bank is very rare, and if it does occur, it is usually gross slippage which will be seen by external detectors. Should it go undetected, the time between the rod position checks performed every shift is short with respect to the probability of occurrence of another independent undetected situation which would further reduce the shutdown capability of the rods.

Any combination of misaligned rods below 10% rated power will not exceed the design limits. For this reason, it is not necessary to check the position of rods with inoperable LVDTs below 10% power; plus, the incore instrumentation is not effective for determining rod position until the power level is above approximately 5%.

Power Distribution

During power operation, the global power distribution is limited by TS 15.3.10.E.2, "Axial Flux Difference," and TS 15.3.10.E.3, "Quadrant Power Tilt," which are directly and continuously measured process variables. These specifications, along with TS 15.3.10.D, "Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

As a result of the increased peaking factors allowed by the new 422V+ fuel, a new column was added to TS 15.3.10.E.1.a. The full power $F^N_{\Delta H}$ peaking factor design limit (radial peaking factor) for 422V+ fuel will increase to 1.77 from the 1.70 value for the OFA fuel. The maximum $F_Q(Z)$ peaking factor limit (total peaking factor) for 422V+ fuel will increase to 2.60 from the 2.50 value for the OFA fuel. The OFA fuel design will retain the current $F^N_{\Delta H}$ and $F_Q(Z)$ peaking factors of 1.70 and 2.50, respectively. In addition, the K(Z) envelope for the new 422V+ fuel was modified and a new TS figure 15.3.10-3a was developed and inserted in the Technical Specifications. The K(Z) envelope in TS Figure 15.3.10-3 remains for the OFA fuel. B Amend 193/198

The purpose of the limits on the values of $F_Q(Z)$, the height dependent heat flux hot channel factor, is to limit the local peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution. $F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

< See LCO 3.2.1 >

The purpose of the limits on $F^N_{\Delta H}$, the nuclear enthalpy rise hot channel factor, is to ensure that the fuel design criteria are not exceded and the accident analysis assumptions remain valid. The design limits on local and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along a fuel rod to the average fuel rod power. Imposed limits pertain to the maximum $F^N_{\Delta H}$ in the core, that is the fuel rod with the highest integrated power. It should be noted that $F^N_{\Delta H}$ is based on an integral and is used as such in the DNB calculations. Local heat flux is obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal (x-y) power shapes throughout the core. Thus, the horizontal power shape at the point of maximum heat flux is not necessarily directly related to $F^N_{\Delta H}$.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least monthly. However, during power operation, the global power distribution is monitored by TS 15.3.10.E.2, "Axial Flux Difference," and TS 15.3.10.E.3, "Quadrant Power Tilt," which address directly and continuously measured process variables.

It has been determined that, provided the following conditions are observed, the hot channel factor limits will be met:

1. Control rods in a single bank move together with no individual rod insertion differing by more than 24 steps from the bank demand position (operation at greater than 85 percent of rated power), nor more than 36 steps (operation at less than or equal to 85 percent of rated power). An indicated misalignment limit of 12 steps precludes a rod misalignment of greater than 24 steps with consideration of instrumentation error; 24 steps indicated misalignment corresponds to 36 steps with instrumentation error. F TSCR 216

2. Control rod banks are sequenced with overlapping banks as described in Figure 15.3.10-1.

3. Control bank insertion limits are not violated.

4. Axial power distribution control procedures, which are given in terms of flux difference control and control bank insertion limits, are observed. Flux difference refers to the difference in signals between the top and bottom halves of two-section excore neutron detectors. The flux difference is a measure of the axial offset which is defined as the difference in normalized power between the top and bottom halves of the core.

The permitted relaxation of $F^N_{\Delta H}$ allows radial power shape changes with rod insertion to the insertion limits. It has been determined that provided the above four conditions are observed, these hot channel factor limits are met. In Specification 15.3.10.E.1.a, F_Q is arbitrarily limited for $p \leq 0.5$.

The upper bound envelope F_Q (defined in 15.3.10.E) times the normalized peaking factor axial dependence of Figure 15.3.10-3 for OFA and Upgraded OFA Fuel and Figure 15.3.10-3a for 422V+ Fuel (consistent with the Technical Specifications on power distribution control as given in Section 15.3.10) was used in the large and small break LOCA analyses. The envelope was determined based on allowable power density distributions at full power restricted to axial flux difference (ΔI) values consistent with those in Specification 15.3.10.E.2.

< See LCO 3.2.1 >

B
Amend 193/198

The results of the analyses based on this upper bound envelope indicate a peak clad temperature of less than the 2200°F limit. When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be taken into account. Five percent is the appropriate allowance for a full core map taken with the moveable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. In the design limit of $F^N_{\Delta H}$, there is eight percent allowance for uncertainties which means that normal operation of the core is expected to result in a design $F^N_{\Delta H} \leq 1.70/1.08$. The logic behind the larger uncertainty in this case is as follows:

(a) Normal perturbations in the radial power shape (i.e., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q.

(b) While the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired value, he has no direct control over $F^N_{\Delta H}$.

A.5

(c) An error in the predictions for radial power shape which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control; but compensation for $F^N_{\Delta H}$ is less readily available.

Measurements of the hot channel factors are required as part of startup physics tests, at least each full power month operation, and whenever abnormal power distribution conditions require a reduction of core power to a level based upon measured hot channel factors. The incore map taken following initial loading provides confirmation of the basic nuclear design bases including proper fuel loading patterns. The periodic monthly incore mapping provides additional assurance that the nuclear design bases remain inviolate and identify operational anomalies which would, otherwise, affect these bases.

The measured hot channel factors are increased as follows:

(a) The measurement of total peaking factor, F_Q^{meas}, shall be increased by three percent to account for manufacturing tolerance and further increased by five percent to account for measurement error.

F
TSCR 216

(b) The measurement of enthalpy rise hot channel factor, $F^N_{\Delta H}$ shall be increased by four percent to account for measurement error. A.5

Axial Power Distribution

< See Section 3.2.3 >

The limits on axial flux difference (AFD) assure that the axial power distribution is maintained such that the $F_Q(Z)$ upper bound envelope of F_Q^{LIMIT} times the normalized axial peaking factor [K(Z)] is not exceeded during either normal operation or in the event of xenon redistribution following power changes. This ensures that the power distributions assumed in the large and small break LOCA analyses will bound those that occur during plant operation.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD monitor alarm. The computer determines the AFD for each of the operable excore channels and provides a computer alarm if the AFD for at least 2 of 4 or 2 of 3 operable excore channels are outside the AFD limits and the reactor power is greater than 50 percent of Rated Power.

Quadrant Tilt

< See Section 3.2.4 >

The quadrant tilt limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, specifications associated with axial flux difference, quadrant tilt, and control rod insertion limits provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

The excore detectors are somewhat insensitive to disturbances near the core center or on the major axes. It is therefore possible that a five percent tilt might actually be present in the core when the excore detectors respond with a two percent indicated quadrant tilt. On the other hand, they are overly responsive to disturbances near the periphery on the 45° axes.

Tilt restrictions are not applicable during the startup and initial testing of a reload core which may have an inherent tilt. During this time sufficient testing is performed at reduced power to verify that the hot channel factor limits are met and the nuclear channels are properly aligned. The excore detectors are normally aligned indicating no quadrant power tilt because they are used to alarm on a rapidly developing tilt. Tilts which develop slowly are more accurately and readily discerned by incore measurements. The excore detectors serve as the prime indication of a quadrant power tilt. If a channel fails, is out-of-service for testing, or is unreliable, two hours is a short time with respect to the probability of an unsafe quadrant power tilt developing. Two hours gives the operating personnel sufficient time to have the problem investigated and/or put into operation one of several possible alternative methods of determining tilt.

F
TSCR
216

TABLE 15.4.1-2 (Continued)

30.	Pressurizer Heaters < See Section 3.4 >	Verify that 100 KW of heaters are available.	Quarterly
31.	CVCS Charging Pumps < See LCO 3.5.2 >	Verify operability pumps.(17)	Quarterly
32.	Potential Dilution in Progress Alarm < See Section 3.3 >	Verify operability of alarm.	Prior to placing plant in cold shutdown.
33.	~~Core Power Distribution~~	~~Perform power distribution maps using movable incore detector system to confirm hot channel factors.~~ LA.2	~~Monthly (20)~~ See Insert 3.2.2-1
34.	Shutdown Margin < See Section 3.1 >	Perform shutdown margin calculation.	Daily (21)

< See LCOs: 3.4.16, 3.5.4, 3.7.18, and 3.4.13 >

(1) Required only during periods of power operation.
(2) Q determination will be started when the gross activity analysis of a filtered sample indicates ³10mCi/cc and will be redetermined if the primary coolant gross radioactivity of a filtered sample increases by more than 10mCi/cc. < See Section 3.4 >
(3) Drop test shall be conducted at rated reactor coolant flow. Rods shall be dropped under both cold and hot condition, but cold drop tests need not be timed. < See LCO 3.1.5 >
(4) Drop tests will be conducted in the hot condition for rods on which maintenance was performed.
(5) As accessible without disassembly of rotor.
(6) Not required during periods of refueling shutdown.
(7) At least once per week during periods of refueling shutdown.
(8) At least three times per week (with maximum time of 72 hours between samples) during periods of refueling shutdown. < See LCO 3.4.16 >
(9) Not required during periods of cold or refueling shutdown, but must be performed prior to exceeding 200°F if it has not been performed during the previous surveillance period. < See LCOs 3.3.1, 3.6.3 >
(10) Sample to be taken after a minimum of 2 EFPD and 20 days power operation since the reactor was last subcritical for 48 hours or longer. < See LCO 3.4.16 >
(11) An approximately equal number of valves shall be tested each refueling outage such that all valves will be tested within a five year period. If any valve fails its tests, an additional < See LCOs 3.7.1, 3.4.10 > originally tested shall be tested. If any of the additional tested valves fail, all remaining valves shall be tested.
(12) The specified buses shall be determined energized in the required manner at least once per shift by verifying correct static transfer switch alignment and indicated voltage on the buses < See Section 3.8 >
(13) Not required if the block valve is shut to isolate a PORV that is inoperable for reasons other than excessive seat leakage. < See LCO 3.4.11 >
(14) Only applicable when the overpressure mitigation system is in service. < See LCO 3.4.12 >
(15) Required to be performed only if conditions will be established, as defined in Specification 15.3.15, where the PORVs are used for low temperature overpressure protection. The test must be performed prior to establishing these conditions.

Associated Specification removed with Unit 1 Amendment 176 and Unit 2 Amendment 180

< See LCOs 3.4.11 and 3.4.12 >

TABLE 15.4.1-2 (Continued)

A.1

(16) Test valve operation in accordance with the inservice test requirements of the ASME Boiler and Pressure Vessel Code, Section XI.

(17) Operability of charging pumps is verified by ensuring that the pumps develop the required flowrate, as specified by the In-Service Test Program.

(18) Not required to be performed if the reactor is subcritical.

(19) Required only when the BAST(s) are relied upon as a source of borated water.

(20) Perform during power operation at effective full power monthly intervals. Following a refueling shutdown, a power distribution map shall be performed prior to exceeding 90% of rated thermal power.

(21) Only applicable during low-power physics testing.

See Insert 3.2.2-1

< See LCO 3.5.2 >

< See LCO 3.1.1 and 3.1.10 >

< See LCO 3.1.5 >

15.3.11 MOVABLE IN-CORE INSTRUMENTATION

Applicability:

Applies to the operability of the movable detector instrumentation system.

Objective:

To specify functional requirements on the use of the in-core instrumentation systems for the recalibration of the excore axial off-set detection system.

Specification:

A. A minimum of 2 thimbles per quadrant and sufficient movable in-core detectors shall be operable during recalibration of the excore axial off-set detection system.

B. Power shall be limited to 90% of rated power if the calibration requirements for excore axial off-set detection system, identified in Table 15.4.1-1, are not met.

Basis:

The Movable In-Core Instrumentation System[1] has four drives, four detectors, and 36 thimbles in the core. The A and B detectors can be routed to eighteen thimbles. The C and D detectors can be routed to twenty-seven thimbles. Consequently, the full system has a great deal more capability than would be needed for the calibration of the ex-core detectors.

To calibrate the excore detectors channels, it is only necessary that the Movable In-Core System be used to determine the gross power distribution in the core as indicated by the power balance between the top and bottom halves of the core.

R.1

After the excore system is calibrated initially, recalibration is needed only infrequently to compensate for changes in the core, due for example to fuel depletion, and for changes in the detectors.

If the recalibration is not performed, the mandated power reduction assures safe operation of the reactor since it will compensate for an error of 10% in the excore protection system. Experience at Beznau (Switzerland) and Ginna has shown that drift due to changes in the core or instrument channels is very slight. Thus, the 10% reduction is considered to be very conservative.

Reference

(1) FSAR - Section 7.4

R.1

INSERT 3.2.2-1:

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 31 EFPD thereafter

LA.1

M.2

A.1

< See Section 3.1 >

A.1

15.3.10 CONTROL ROD AND POWER DISTRIBUTION LIMITS

Applicability

Applies to the operation of the control rods and to core power distribution limits.

A.2

A.3

Objective

< See Section 3.1 >

~~To insure~~ (1) core subcriticality after a reactor trip, (2) a limit on potential reactivity insertions from a hypothetical rod cluster control assembly (RCCA) ejection, and (3) an ~~acceptable~~ core power distribution ~~during~~ power operation.

Specification

< See Section 3.1 >

A. SHUTDOWN MARGIN

1. The shutdown margin shall exceed the applicable value as shown in Figure 15.3.10-2 under all steady-state operating conditions from 350°F to full power. If the shutdown margin is less than the applicable value of Figure 15.3.10-2, within 15 minutes initiate boration to restore the shutdown margin.

2. A shutdown margin of at least 1% Δk/k shall be maintained when the reactor coolant temperature is less than 350°F. If the shutdown margin is less than this limit, within 15 minutes initiate boration to restore the shutdown margin.

B. ROD OPERABILITY AND BANK ALIGNMENT LIMITS

NOTE: One hour is allowed following rod motion prior to verifying rod operability and bank alignment limits.

1. During power and low power operation, all shutdown and control rods shall be operable and positioned within the allowed rod misalignment between the individual indicated rod positions and the bank demand position as follows;

i) For operation ≤ 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±24 steps.

ii) For operation > 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±12 steps.

F TSCR 216

If an RCCA does not step in upon demand, up to six hours is allowed to determine whether the problem with stepping is an electrical problem. If the problem cannot be resolved within six hours, the RCCA shall be declared inoperable until it has been verified that it will step in or would drop upon demand.

F TSCR 216

A.1 < See Section 3.2.2 >

(7) If the above actions and associated completion times are not met, be in hot shutdown within the following six hours.

2. Axial Flux Difference

LCO Note

NOTE: The axial flux difference shall be considered outside limits when two or more operable excore channels indicate that axial flux difference is outside limits .

Applicability

LCO

a. During power operation with thermal power ≥50 percent of rated thermal power, the axial flux difference shall be maintained within the limits specified in ~~Figure 15.3.10-4.~~ the COLR. LA.1

L.1

(1) ~~If the axial flux difference is not within limits, within 15 minutes restore to within limits. If this action and associated completion time is not met, perform the following actions:~~

~~(a) Reduce thermal power until the axial flux difference is within limits;~~
~~OR~~

M.2

Cond A and RA A.1

(b) Within three hours reduce thermal power to ~~≤50~~ < 50% percent of rated thermal power. M.2

L.2

~~b. If it is necessary to restrict thermal power to ≤50 percent of rated thermal power, within the next four hours reduce the Power Range Neutron Flux - High Trip setpoints to ≤55 percent.~~

L.3

~~c. If the alarms used to monitor the axial flux difference are rendered inoperable, verify that the axial flux difference is within limits for each operable excore channel once within one hour and every hour thereafter.~~

Insert 3.2.3-1

3. Quadrant Power Tilt

a. During power operation with thermal power greater than 50 percent of rated thermal power, the indicated quadrant power tilt shall not exceed 2 percent. If this condition is not met, perform the following actions:

(1) Within two hours, reduce thermal power ≥2 percent from rated thermal power for each 1 percent of indicated quadrant power tilt;
AND

(2) Within 24 hours and once per seven days thereafter, verify that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the limits of Specification 15.3.10.E.1.a;
AND

< See Section 3.2.4 >

< See LCO 3.2.2 >

The permitted relaxation of $F^N_{\Delta H}$ allows radial power shape changes with rod insertion to the insertion limits. It has been determined that provided the above four conditions are observed, these hot channel factor limits are met. In Specification 15.3.10.E.1.a, F_Q is arbitrarily limited for $p \leq 0.5$.

The upper bound envelope F_Q (defined in 15.3.10.E) times the normalized peaking factor axial dependence of Figure 15.3.10-3 for OFA and Upgraded OFA Fuel and Figure 15.3.10-3a for 422V+ Fuel (consistent with the Technical Specifications on power distribution control as given in Section 15.3.10) was used in the large and small break LOCA analyses. The envelope was determined based on allowable power density distributions at full power restricted to axial flux difference (ΔI) values consistent with those in Specification 15.3.10.E.2. < See LCO 3.2.1 >

B
Amend 193/198

The results of the analyses based on this upper bound envelope indicate a peak clad temperature of less than the 2200°F limit. When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be taken into account. Five percent is the appropriate allowance for a full core map taken with the moveable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. In the design limit of $F^N_{\Delta H}$, there is eight percent allowance for uncertainties which means that normal operation of the core is expected to result in a design $F^N_{\Delta H} \leq 1.70/1.08$. The logic behind the larger uncertainty in this case is as follows:

< See LCO 3.2.2 >

(a) Normal perturbations in the radial power shape (i.e., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q.

(b) While the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired value, he has no direct control over $F^N_{\Delta H}$.

(c) An error in the predictions for radial power shape which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control; but compensation for $F^N_{\Delta H}$ is less readily available.

Measurements of the hot channel factors are required as part of startup physics tests, at least each full power month operation, and whenever abnormal power distribution conditions require a reduction of core power to a level based upon measured hot channel factors. The incore map taken following initial loading provides confirmation of the basic nuclear design bases including proper fuel loading patterns. The periodic monthly incore mapping provides additional assurance that the nuclear design bases remain inviolate and identify operational anomalies which would, otherwise, affect these bases.

The measured hot channel factors are increased as follows:

(a) The measurement of total peaking factor, F_Q^{meas}, shall be increased by three percent to account for manufacturing tolerance and further increased by five percent to account for measurement error.

F
TSCR
216

< See LCO 3.2.2 >

(b) The measurement of enthalpy rise hot channel factor, $F^N_{\Delta H}$ shall be increased by four percent to account for measurement error.

Axial Power Distribution

< See Section 3.2.3 >

The limits on axial flux difference (AFD) assure that the axial power distribution is maintained such that the $F_Q(Z)$ upper bound envelope of F_Q^{LIMIT} times the normalized axial peaking factor [K(Z)] is not exceeded during either normal operation or in the event of xenon redistribution following power changes. This ensures that the power distributions assumed in the large and small break LOCA analyses will bound those that occur during plant operation.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD monitor alarm. The computer determines the AFD for each of the operable excore channels and provides a computer alarm if the AFD for at least 2 of 4 or 2 of 3 operable excore channels are outside the AFD limits and the reactor power is greater than 50 percent of Rated Power.

< See Section 3.2.3 >

Quadrant Tilt

A.5

The quadrant tilt limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, specifications associated with axial flux difference, quadrant tilt, and control rod insertion limits provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

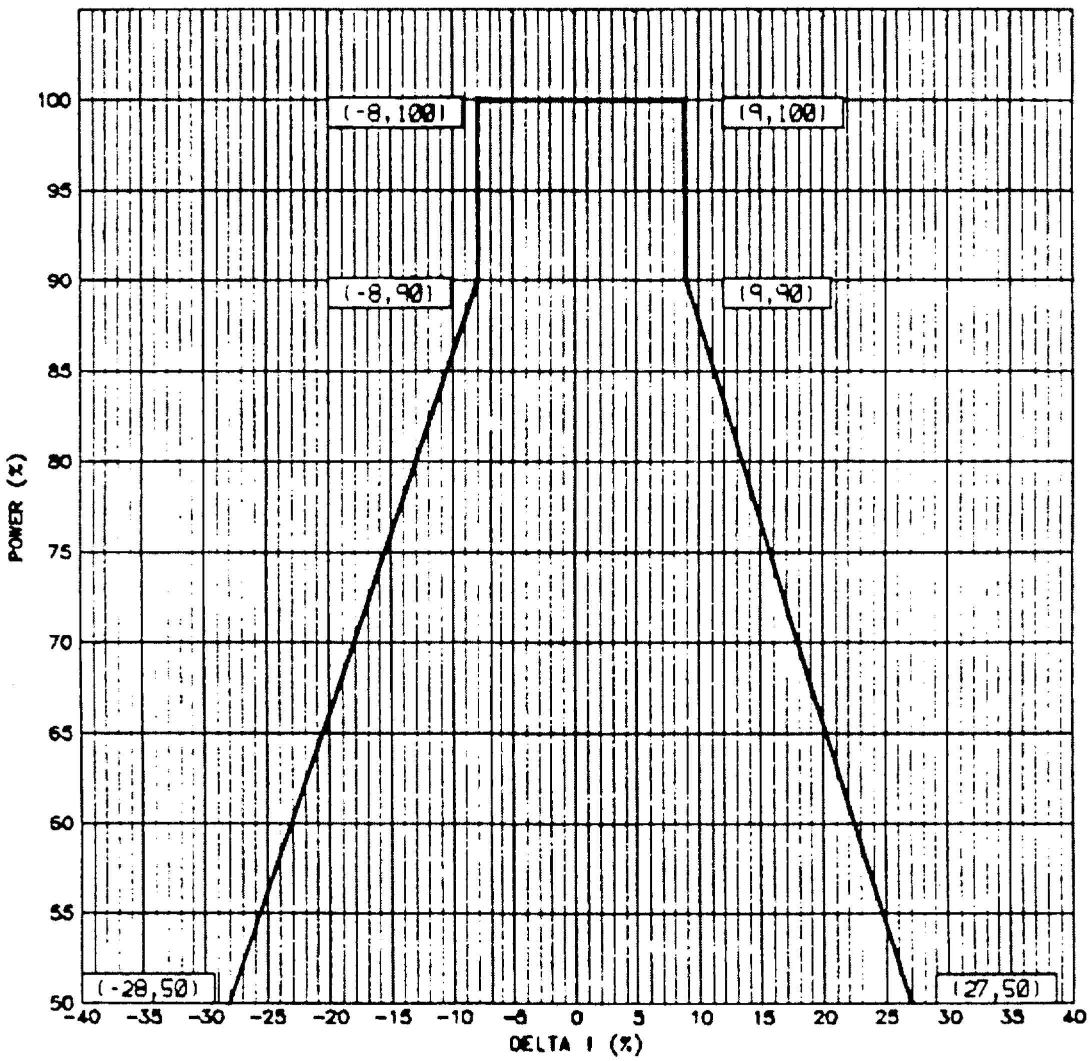
The excore detectors are somewhat insensitive to disturbances near the core center or on the major axes. It is therefore possible that a five percent tilt might actually be present in the core when the excore detectors respond with a two percent indicated quadrant tilt. On the other hand, they are overly responsive to disturbances near the periphery on the 45^{O} axes.

Tilt restrictions are not applicable during the startup and initial testing of a reload core which may have an inherent tilt. During this time sufficient testing is performed at reduced power to verify that the hot channel factor limits are met and the nuclear channels are properly aligned. The excore detectors are normally aligned indicating no quadrant power tilt because they are used to alarm on a rapidly developing tilt. Tilts which develop slowly are more accurately and readily discerned by incore measurements. The excore detectors serve as the prime indication of a quadrant power tilt. If a channel fails, is out-of-service for testing, or is unreliable, two hours is a short time with respect to the probability of an unsafe quadrant power tilt developing. Two hours gives the operating personnel sufficient time to have the problem investigated and/or put into operation one of several possible alternative methods of determining tilt.

LA.1

FIGURE 15.3.10-4

FLUX DIFFERENCE
OPERATING ENVELOPE
POINT BEACH UNITS 1 AND 2



INSERT 3.2.3-1:

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD within limits for each OPERABLE excore channel.	7 days

M.1

< See Section 3.1 >

A.1

15.3.10 CONTROL ROD AND POWER DISTRIBUTION LIMITS

Applicability

Applies to the operation of the control rods and to core power distribution limits.

A.2

Objective

< See Section 3.1 >

~~To~~ insure (1) core subcriticality after a reactor trip, (2) a limit on potential reactivity insertions from a hypothetical rod cluster control assembly (RCCA) ejection, and (3) an ~~acceptable~~ core power distribution ~~during~~ power operation.

A.3

Specification

< See Section 3.1 >

A. SHUTDOWN MARGIN

1. The shutdown margin shall exceed the applicable value as shown in Figure 15.3.10-2 under all steady-state operating conditions from 350°F to full power. If the shutdown margin is less than the applicable value of Figure 15.3.10-2, within 15 minutes initiate boration to restore the shutdown margin.

2. A shutdown margin of at least 1% $\Delta k/k$ shall be maintained when the reactor coolant temperature is less than 350°F. If the shutdown margin is less than this limit, within 15 minutes initiate boration to restore the shutdown margin.

B. ROD OPERABILITY AND BANK ALIGNMENT LIMITS

NOTE: One hour is allowed following rod motion prior to verifying rod operability and bank alignment limits.

1. During power and low power operation, all shutdown and control rods shall be operable and positioned within the allowed rod misalignment between the individual indicated rod positions and the bank demand position as follows;

   i) For operation ≤ 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±24 steps.
   ii) For operation > 85 percent of rated power, the allowed indicated misalignment between the bank demand position and the individual indicated rod position shall be ≤ ±12 steps.

   If an RCCA does not step in upon demand, up to six hours is allowed to determine whether the problem with stepping is an electrical problem. If the problem cannot be resolved within six hours, the RCCA shall be declared inoperable until it has been verified that it will step in or would drop upon demand.

F
TSCR
216

F
TSCR
216

< See LCO 3.2.2 >

The permitted relaxation of $F^N_{\Delta H}$ allows radial power shape changes with rod insertion to the insertion limits. It has been determined that provided the above four conditions are observed, these hot channel factor limits are met. In Specification 15.3.10.E.1.a, F_Q is arbitrarily limited for $p \leq 0.5$.

The upper bound envelope F_Q (defined in 15.3.10.E) times the normalized peaking factor axial dependence of Figure 15.3.10-3 for OFA and Upgraded OFA Fuel and Figure 15.3.10-3a for 422V+ Fuel (consistent with the Technical Specifications on power distribution control as given in Section 15.3.10) was used in the large and small break LOCA analyses. The envelope was determined based on allowable power density distributions at full power restricted to axial flux difference (ΔI) values consistent with those in Specification 15.3.10.E.2.

< See LCO 3.2.1 >

B
Amend
193/198

The results of the analyses based on this upper bound envelope indicate a peak clad temperature of less than the 2200°F limit. When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be taken into account. Five percent is the appropriate allowance for a full core map taken with the moveable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. In the design limit of $F^N_{\Delta H}$, there is eight percent allowance for uncertainties which means that normal operation of the core is expected to result in a design $F^N_{\Delta H} \leq 1.70/1.08$. The logic behind the larger uncertainty in this case is as follows:

< See LCO 3.2.2 >

(a) Normal perturbations in the radial power shape (i.e., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q.

(b) While the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired value, he has no direct control over $F^N_{\Delta H}$.

(c) An error in the predictions for radial power shape which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control; but compensation for $F^N_{\Delta H}$ is less readily available.

Measurements of the hot channel factors are required as part of startup physics tests, at least each full power month operation, and whenever abnormal power distribution conditions require a reduction of core power to a level based upon measured hot channel factors. The incore map taken following initial loading provides confirmation of the basic nuclear design bases including proper fuel loading patterns. The periodic monthly incore mapping provides additional assurance that the nuclear design bases remain inviolate and identify operational anomalies which would, otherwise, affect these bases.

The measured hot channel factors are increased as follows:

(a) The measurement of total peaking factor, F_Q^{meas}, shall be increased by three percent to account for manufacturing tolerance and further increased by five percent to account for measurement error.

F
TSCR

< See LCO 3.2.2 >

(b) The measurement of enthalpy rise hot channel factor, $F^N_{\Delta H}$ shall be increased by four percent to account for measurement error.

Axial Power Distribution

< See Section 3.2.3 >

The limits on axial flux difference (AFD) assure that the axial power distribution is maintained such that the $F_Q(Z)$ upper bound envelope of F_Q^{LIMIT} times the normalized axial peaking factor [K(Z)] is not exceeded during either normal operation or in the event of xenon redistribution following power changes. This ensures that the power distributions assumed in the large and small break LOCA analyses will bound those that occur during plant operation.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD monitor alarm. The computer determines the AFD for each of the operable excore channels and provides a computer alarm if the AFD for at least 2 of 4 or 2 of 3 operable excore channels are outside the AFD limits and the reactor power is greater than 50 percent of Rated Power.

< See Section 3.2.3 >

Quadrant Tilt

A.5

The quadrant tilt limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, specifications associated with axial flux difference, quadrant tilt, and control rod insertion limits provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

The excore detectors are somewhat insensitive to disturbances near the core center or on the major axes. It is therefore possible that a five percent tilt might actually be present in the core when the excore detectors respond with a two percent indicated quadrant tilt. On the other hand, they are overly responsive to disturbances near the periphery on the 45^{0} axes.

Tilt restrictions are not applicable during the startup and initial testing of a reload core which may have an inherent tilt. During this time sufficient testing is performed at reduced power to verify that the hot channel factor limits are met and the nuclear channels are properly aligned. The excore detectors are normally aligned indicating no quadrant power tilt because they are used to alarm on a rapidly developing tilt. Tilts which develop slowly are more accurately and readily discerned by incore measurements. The excore detectors serve as the prime indication of a quadrant power tilt. If a channel fails, is out-of-service for testing, or is unreliable, two hours is a short time with respect to the probability of an unsafe quadrant power tilt developing. Two hours gives the operating personnel sufficient time to have the problem investigated and/or put into operation one of several possible alternative methods of determining tilt.

DOC Number	DOC Text	
M.30 Rev. D	CTS Table 15.4.1-1, surveillance requirement to compare results of incore detector measurements to NIS axial flux difference has been modified by a Note clarifying this surveillance is not required to be performed until 24 hours after THERMAL POWER is greater than or equal to 50% RTP. Per CTS 15.4.0.4, the reactor shall not be placed in a condition where a system or component is required to be operable, if the specified surveillances have not been performed satisfactorily within their specified frequencies. However, CTS 15.4.0.4 also states if entry into a condition where the system or component is required to be operable is necessary in order to perform the specified surveillance, entry into the operating conditions may be made provided prior testing or inspection provides reasonable assurance of operability, and the surveillance is performed as soon as practicable following entry into the required operating condition. Point Beach operating experience has shown that an accurate comparison of incore detector measurements to NIS axial flux difference cannot be made at lower reactor powers. Therefore, adoption of ITS SR 3.3.1.3, Note 2 is consistent with current operating practice and the requirements of CTS 15.4.0.4. However, specifying the surveillance is "required to be performed within 24 hours after THERMAL POWER is greater than or equal to 50% RTP," is more restrictive than the CTS requirement of "as soon as practicable following entry into the required operating condition.	
	CTS:	**ITS:**
	15.04.0.04	SR 3.03.01.03 NOTE 2
M.31 Rev. F	Not used.	
	CTS:	**ITS:**
	N/A	N/A
M.32 Rev. D	CTS 15.4.1, Table 15.4.1-1, Function 16, Reactor Trip Signal from SI, has been modified by the addition of SR 3.3.1.13, TADOT, with a frequency of 18 months. Performance of this SR will ensure that the SI input to RPS for initiation of a reactor trip is operable. Adopting this SR imposes additional requirements on unit operation and is therefore more restrictive. This change is consistent with NUREG-1431.	
	CTS:	**ITS:**
	NEW	SR 3.03.01.13

C. Other reactor trips:

Table 3.3.1-1, #8

D
Errata #70

(1) High pressurizer water level - ≤95% of span

(2) Low-low steam generator water level - ≥20% of narrow range instrument span

Table 3.3.1-1, #13

D
Errata #70

(3) Steam-Feedwater Flow Mismatch Trip - ≤1.0 x 10^6 lb/hr

Table 3.3.1-1, #14

(4) Turbine Trip (Not a protection circuit)

Table 3.3.1-1, #15.a, 15.b

(5) Safety Injection Signal

Table 3.3.1-1, #16

(6) Manual Trip

Table 3.3.1-1, #1

F
RAI 3.3.1-26

F
RAI 3.3.1-27

D
RAI 3.3.1-26

JFD Number	JFD Text	
67 Rev. A	LCO 3.3.1 Bases discussion of SR 3.3.1.7 has been modified to reflect Point Beach setpoint methodology. The "as found" and "as left" values obtained during the performance of a COT are verified to be within limits. These values are not reviewed for consistency with the assumptions of WCAP-10271-P-A, Supplement 2. Additionally, text added to the Bases description of SR 3.3.1.7, via TSTF-205, has not been incorporated into the ITS. Point Beach design of RPS necessitates COT testing which is inconsistent with the verbiage added by TSTF-205. **ITS:** B 3.03.01	**NUREG:** B 3.03.01
68 Rev. A	ITS LCO 3.3.1 Bases discussion of undervoltage and shunt trip "mechanisms" has been changed to undervoltage and shunt trip "circuits" to reflect Point Beach design for these devices. **ITS:** B 3.03.01	**NUREG:** B 3.03.01
69 Rev. D	ITS LCO 3.3.1 Bases discussion of SR 3.3.1.3 has been modified to indicate the SR is performed by means of a movable incore detector system. This addition to the Bases retains information previously contained in the CTS. **ITS:** B 3.03.01	**NUREG:** B 3.03.01
70 Rev. F	The Allowable Values associated with the SG Water Level – Low and Turbine Trip – Low Autostop Oil Pressure reactor trips have been designated as "NA." No analytical limit or Allowable Value has been established for any of these functions as they are not credited in the safety analysis for the mitigation of any accident. SG Water Level – Low is an anticipatory trip for the SG Water Level – Low Low trip for the mitigation of a Loss of Normal Feedwater event. Reactor trip on Turbine trip is an anticipatory trip to other reactor trips that would be challenged by a load rejection event (OTdeltaT, Pressurizer Pressure – High, and SG Water Level – Low Low). Each of the above Functions will have a nominal setting identified in the Bases. These nominal settings were developed outside of the setpoint methodology and have been provided by the NSSS supplier. **ITS:** B 3.03.01	**NUREG:** B 3.03.01

Table 3.3.1-1 (page 4 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

FUNCTION	~~APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS~~ APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT(a)~~
~~11.~~ 10. Reactor Coolant Pump (RCP) Breaker Position						
a. Single Loop	1 ~~(f)~~ (h)	1 per RCP	~~M~~ O	SR 3.3.1. ~~14~~ 13	NA	~~NA~~
b. Two Loops	1 ~~(g)~~ (i)	1 per RCP	~~N~~ M	SR 3.3.1. ~~14~~ 13	NA	~~NA~~
~~12.~~ 11. Undervoltage ~~RCPs~~ Bus A01 and A02	1 ~~(e)~~ (g)	~~2~~ [3] per bus	~~K~~ M	SR 3.3.1.9 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[4760] V~~ 3120 V	~~≥ [4830] V~~
~~13.~~ 12. Underfrequency ~~RCPs~~ Bus A01 and A02	1 ~~(e)~~ (g)	~~2~~ [3] per bus	~~E~~ M	~~SR 3.3.1.9~~ SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[57.1]~~ 55.0 Hz	~~≥ [57.5] Hz~~
~~14.~~ 13. Steam Generator (SG) Water Level – Low Low	1,2	~~3 per SG~~ [4 per SG]	~~D~~ E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~[30.4]%~~ 20% of span	~~≥ [32.3]%~~
~~15.~~ 14. SG Water Level – Low	1,2	2 per SG	~~D~~ E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1. ~~10~~ 11 ~~SR 3.3.1.16~~	~~≥ [30.4]%~~ NA	~~≥ [32.3]%~~
Coincident with Steam Flow/Feedwater Flow Mismatch	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	~~≤ [42.5]% full steam flow at RTP~~ ≤ 1 E6 lbm/hr	~~≤ [40]% full steam flow at RTP~~

Approved TSTF-135

(continued)

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

~~(e)~~ (g) Above the P-7 (Low Power Reactor Trips Block) interlock.

~~(f)~~ (h) Above the P-8 (Power Range Neutron Flux) interlock.

~~(g)~~ (i) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

D RAI 3.3.1-1 Errata #145

F RAI 3.3.1-26

D RAI 3.3.1-8 RAI 3.3.1-10 RAI 3.3.1-26 Errata #145

F RAI 3.3.1-26

Table 3.3.1-1 (page 5 of 8)
Reactor Trip System Instrumentation (Trip → Protection ← 60)

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS (APPLICABLE MODES ← 15)	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT[a] (27)
16. (15. ← 29) Turbine Trip (Autostop ← 36)						
a. Low Fluid Oil Pressure	1[j]	3 (37: 2 → 4)	O; P	~~SR 3.3.1.10~~ SR 3.3.1.15 (38; 55: 14)	≥ [750] psig (70: NA)	≥ [800] psig
b. Turbine Stop Valve Closure	1[j]	4	P	~~SR 3.3.1.10~~ SR 3.3.1.15 (38)	≥ [1]% open (16: NA)	≥ [1]% open
17. (16. ← 29) Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	Q (Approved TSTF-135: P)	SR 3.3.1.14 (55: 13)	NA	NA
18. (17. ← 29) Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	2[e] (26: (d))	2	R → S (Approved TSTF-135)	SR 3.3.1.11 SR 3.3.1.13 (55: 12)	≥ [6E-11] amp (16: > 1E-10)	≥ [1E-10] amp
Replace with Insert 17.b ← 39						
~~b. Low Power Reactor Trips Block, P-7~~	~~1~~	~~1 per train~~	~~T~~	~~SR 3.3.1.11 SR 3.3.1.13~~	~~NA~~	NA
c. Power Range Neutron Flux, P-8	1	4	S → T (Approved TSTF-135)	SR 3.3.1.11 SR 3.3.1.13 (55: 12)	≤ [50.2]% RTP (16: < 50)	≤ [48]% RTP
d. Power Range Neutron Flux, P-9	1 (k) (40)	4	S → T	SR 3.3.1.11 SR 3.3.1.13 (12)	≤ [52.2]% RTP (16: < 50)	≤ [50]% RTP
e. Power Range Neutron Flux, P-10	1,2	4	R → S (Approved TSTF-135)	SR 3.3.1.11 SR 3.3.1.13 (55: 12)	≥ [7.8]% RTP and ≤ [12.2]% RTP (16: > 8; < 10)	≥ [10]% RTP
~~f. Turbine Impulse Pressure, P-13~~ (39)	~~1~~	~~2~~	~~T~~	~~[SR 3.3.1.1] SR 3.3.1.10 SR 3.3.1.13~~	~~≤ [12.2]% turbine power~~	≤ [10]% turbine power

F RAI 3.3.1-27

F Errata #184 RAI 3.3.1-26 RAI 3.3.1-27

(continued)

26 → ~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

(26: (d)) (e) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(j) Above the P-9 (Power Range Neutron Flux) interlock.

(k) With 1 of 2 circulating water pump breakers closed and vacuum ≥ 22"Hg. ← 40

F RAI 3.3.1-26 RAI 3.3.1-27

Insert 17.a-02

NOT USED

Insert 17.b

(1) Power Range Neutron Flux	1	4	S	SR 3.3.1.11 SR 3.3.1.12	< 10% RTP
(2) Turbine Impulse Pressure	1	2	S	SR 3.3.1.11 SR 3.3.1.12	< 10% turbine power

F

Errata #184

Insert 17.d

Not used.

Table 3.3.1-1 (page 6 of 8)
Reactor ~~Trip~~ System Instrumentation 60 Protection

Approved TSTF-135 15 27 29 42 26 20 44 33 Approved TSTF-135

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT(a)~~
18 19. Reactor Trip Breakers (k) (RTBs)	1, 2	2 ~~trains~~	R Q	SR 3.3.1.4	NA	~~NA~~
	3(b), 4(b), 5(b)	2 ~~trains~~	T C	SR 3.3.1.4	NA	~~NA~~
20 19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	(a) 1, 2	1 each per RTB	U U	SR 3.3.1.4	NA	~~NA~~
	3(b), 4(b), 5(b) (a)	1 each per RTB	T C	SR 3.3.1.4	NA	~~NA~~
21. Automatic Trip Logic	1, 2	2 trains	Q P	SR 3.3.1.5 SR 3.3.1.15	NA	~~NA~~
	3(b), 4(b), 5(b)	2 trains	C X	SR 3.3.1.5	NA	~~NA~~

Approved TSTF-135 D RAI 3.3.1-1 RAI 3.3.1-26

26

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~ 26

(a) (b) With RTBs closed and Rod Control System capable of rod withdrawal.

~~(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.~~ 42

(l) When a Reactor Trip Bypass Breaker is racked in and closed and the Rod Control System is capable of rod withdrawal.

F RAI 3.3.1-26 RAI 3.3.1-27

20. Reactor Trip Bypass Breaker and associated Undervoltage Trip Mechanism	1(l), 2(l)	1	V	SR 3.3.1.4	NA	NA
	3(l), 4(l), 5(l)	1	W	SR 3.3.1.4	NA	NA

43

60 RPS

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level -Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

15

29 14

Steam Generator Water Level -Low, Coincident With Steam Flow/Feedwater Flow Mismatch

63

SG Water Level -Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink ~~and actuates the AFW System prior to uncovering the SG tubes~~. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to determine if feedwater flow is significantly less than steam flow. With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. There are two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel sensing a low level coincident with one Steam Flow/ Feedwater Flow Mismatch channel sensing flow mismatch (steam flow greater than feed flow) will actuate a reactor trip.

70

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA), because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The nominal setting required for the Steam Generator Water Level-Low trip function is 30% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.

54 F RAI 3.3.1-26

per SG

The LCO requires two channels of SG Water Level -Low coincident with Steam Flow/Feedwater Flow Mismatch.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level -Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

or 6, the SG Water Level - Low coincident with Steam Flow/Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

29 15 16.

Turbine Trip

a. Turbine Trip - Low Fluid Oil Pressure Autostop 36

The Turbine Trip - Low Fluid Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint, approximately 50% power, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves.

D RAI 3.3.1-7

40 with at least one circulating water pump breaker closed and condenser pressure not high,

D RAI 3.3.1-27

70 Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Turbine Trip – Low Autostop Oil Pressure trip function is 45 psig. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.

F RAI 3.3.1-27

The LCO requires three channels of Turbine Trip - Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-9.

Autostop 36

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the

ACTIONS (continued)

Approved TSTF-135

~~sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.~~

K.1 and K.2 Approved TSTF-135

M.1 and M.2 K

D RAI 3.3.1-1 Errata #145

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low (Two Loops); and
- ~~RCP Breaker Position (Two Loops);~~ 14
- Undervoltage RCPs; and Bus A01 & A02. 34
- ~~Underfrequency RCPs.~~ 15

F RAI 3.3.1-1

1 hour 72

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint interlock and below the P-8 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint interlock. ~~The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7.~~ An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

61 interlock
61 interlock
72

D RAI 3.3.1-4 RAI 3.3.1-2
D RAI 3.3.1-2
D RAI 3.3.1-4

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant

Table 3.3.1-1 (page 3 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
12.	Underfrequency Bus A01 & A02	1[e]	2 per bus	E	SR 3.3.1.10	≥ 55.0 Hz
13.	Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥ 20% of span
14.	SG Water Level — Low	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	NA
	Coincident with Steam Flow/Feedwater Flow Mismatch	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1 E6 lbm/hr
15.	Turbine Trip					
	a. Low Autostop Oil Pressure	1[j]	3	O	SR 3.3.1.14	NA
	b. Turbine Stop Valve Closure	1[j]	2	O	SR 3.3.1.14	NA
16.	Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	P	SR 3.3.1.13	NA

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

(j) Above the P-9 (Power Range Neutron Flux) interlock.

F
RAI 3.3.1-26
RAI 3.3.1-27

Table 3.3.1-1 (page 4 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
17.	Reactor Trip System Interlocks					
	a. Intermediate Range Neutron Flux, P-6	2(d)	2	R	SR 3.3.1.11 SR 3.3.1.12	> 1E-10 amp
	b. Low Power Reactor Trips Block, P-7					
	(1) Power Range Neutron Flux	1	4	S	SR 3.1.1.11 SR 3.3.1.12	< 10% RTP
	(2) Turbine Impulse Pressure	1	2	S	SR 3.3.1.11 SR 3.3.1.12	< 10% turbine power
	c. Power Range Neutron Flux, P-8	1	4	S	SR 3.3.1.11 SR 3.3.1.12	< 50% RTP
	d. Power Range Neutron Flux, P-9	1(k)	4	S	SR 3.3.1.11 SR 3.3.1.12	< 50% RTP
	e. Power Range Neutron Flux, P-10	1,2	4	R	SR 3.3.1.11 SR 3.3.1.12	> 8% RTP and < 10% RTP
18.	Reactor Trip Breakers (RTBs)	1,2	2 trains	Q	SR 3.3.1.4	NA
		3(a), 4(a), 5(a)	2 trains	T	SR 3.3.1.4	NA
19.	Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U	SR 3.3.1.4	NA
		3(a), 4(a), 5(a)	1 each per RTB	T	SR 3.3.1.4	NA

F
Errata #184
RAI 3.3.1-26
RAI 3.3.1-27

(continued)

(a) With the RTBs closed and the Rod Control System capable of rod withdrawal.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.

(k) With 1 of 2 circulating water pump breakers closed and condenser vacuum ≥ 22 "Hg.

F
RAI 3.3.1-26
RAI 3.3.1-27

Table 3.3.1-1 (page 5 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
20.	Reactor Trip Bypass Breaker and associated Undervoltage Trip Mechanism	1[l], 2[l]	1	V	SR 3.3.1.4	NA
		3[l], 4[l], 5[l]	1	W	SR 3.3.1.4	NA
21.	Automatic Trip Logic	1, 2,	2 trains	P	SR 3.3.1.5 SR 3.3.1.15	NA
		3[a], 4[a], 5[a]	2 trains	X	SR 3.3.1.5	NA

(a) With RTBs closed and Rod Control System capable of rod withdrawal.

(l) When Reactor Trip Bypass Breakers are racked in and closed and the Rod Control System is capable of rod withdrawal.

F

RAI 3.3.1-26
RAI 3.3.1-27

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. There are two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel sensing a low level coincident with one Steam Flow/ Feedwater Flow Mismatch channel sensing flow mismatch (steam flow greater than feed flow) will actuate a reactor trip.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA), because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The nominal setting required for the Steam Generator Water Level-Low trip function is 30% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier. F RAI 3.3.1-26

The LCO requires two channels of SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch per SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15. Turbine Trip

a. Turbine Trip-Low Autostop Oil Pressure

The Turbine Trip-Low Autostop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint (approximately 50% power, with at least one circulating water D RAI 3.3.1-27

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

pump breaker closed, and condenser vacuum not high, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function and RCS integrity is ensured by the pressurizer safety valves.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Turbine Trip – Low Autostop Oil Pressure trip function is 45 psig. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier. F RAI 3.3.1-27

The LCO requires three channels of Turbine Trip-Low Autostop Oil Pressure to be OPERABLE in MODE 1 above P-9. D RAI 3.3.1-7

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip-Low Autostop Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip-Turbine Stop Valve Closure

The Turbine Trip-Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. Any turbine trip with from a power level below the P-9 setpoint, approximately 50% power, with at least one circulating water pump breaker closed, and condenser vacuum not high, will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip-Low Autostop Oil D RAI 3.3.1-27

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RPS. If both limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

No analytical value is assumed in the accident analyses for this function. The LCO requires two Turbine Trip-Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. Both channels must trip to cause reactor trip. D RAI 3.3.1-7

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip-Stop Valve Closure trip Function does not need to be OPERABLE.

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

17. Reactor Protection System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed; and
- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint. D RAI 3.3.1-12

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

b. Low Power Reactor Trips Block, P-7 D RAI 3.3.1-14

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either Power Range Neutron Flux or Turbine Impulse Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Open (Two Loops);

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

- Undervoltage Bus A01 and A02; and
- Underfrequency Bus A01 and A02.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:
- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage Bus A01 and A02; and
- Underfrequency Bus A01 and A02.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5 or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1. D RAI 3.3.1-14

Power Range Neutron Flux

Power Range Neutron Flux is actuated by two-out-of-four NIS power range channels. The LCO requirement for this Function ensures that this input to the P-7 interlock is available.

The LCO requires four channels of Power Range Neutron Flux to be OPERABLE in MODE 1.

OPERABILITY in MODE 1 ensures the Function is available to perform its increasing power Functions.

Turbine Impulse Pressure

The Turbine Impulse Pressure interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure interlock to be OPERABLE in MODE 1.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

The Turbine Impulse Chamber Pressure interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

D RAI 3.3.1-14

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors.

The P-8 interlock automatically enables the Reactor Coolant Flow-Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 50% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

D RAI 3.3.1-14 RAI 3.3.1-27

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock, is actuated at approximately 50% power, as determined by two-out-of-four NIS power range detectors, if the Steam Dump System is available. The LCO requirement for this Function ensures that the Turbine Trip-Low Autostop Oil Pressure and Turbine Trip-Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock, to be OPERABLE in MODE 1 with one of two circulating water pump breakers closed and condenser vacuum greater than or equal to 22 “Hg.

BASES

ACTIONS (continued)

- Undervoltage Bus A01 and A02.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 1 hour. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 interlock and below the P-8 setpoint. These Functions do not have to be OPERABLE below the P-7 interlock because there are no loss of flow trips below the P-7 interlock. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

F RAI 3.3.1-1 F RAI 3.3.1-2 D RAI 3.3.1-4

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

L.1 and L.2

Condition L applies to the Reactor Coolant Flow-Low (Single Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be placed in the tripped condition within 1 hour. If the channel cannot be restored to OPERABLE status or the channel placed in trip within the 1 hour, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours. This places the unit in a MODE where the LCO is no longer applicable. This trip Function does not have to be OPERABLE below the P-8 setpoint because other RPS trip Functions provide core protection below the P-8 setpoint.

F RAI 3.3.1-2

M.1 and M.2

Condition M applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel(s) must be restored to OPERABLE status within 1 hour. If the channel cannot be restored to OPERABLE status within the 1 hour, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint.

BASES

ACTIONS (continued)

N.1 and N.2 D RAI 3.3.1-1 Errata #145

Condition N applies to the RCP Breaker Position (Two Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 1 hour. If the channel cannot be restored to OPERABLE status in 1 hour, then THERMAL POWER must be reduced below the P-7 interlock within the next 6 hours. This places the unit in a MODE where the LCO is no longer applicable. This function does not have to be OPERABLE below the P-7 interlock because there are no loss of flow trips below the P-7 interlock. D RAI 3.3.1-1 RAI 3.3.1-10 RAI 3.3.1-8 Errata #145 The Completion Time of 6 hours is reasonable, based on operating experience, to reduce THERMAL POWER to below the P-7 interlock from full power in an orderly manner without challenging unit systems.

O.1 and O.2

Condition O applies to Turbine Trip on Low Autostop Oil Pressure or on Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 1 hour. F RAI 3.3.1-2 If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours.

P.1 and P.2

Condition P applies to the SI Input from ESFAS reactor trip and the RPS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RPS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action P.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours (Required Action P.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action P.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train for up to 8 hours for surveillance testing, provided the other train is OPERABLE.

DOC Number	DOC Text	
M.07 Rev. E	The Operator Actions of CTS Table 15.3.5-4, items 2.d, Steam Line Isolation - Manual, require the unit be in hot shutdown in 8 hours, if the Conditions of Column 3, Minimum Operable Channels, cannot be met. ITS LCO 3.3.2, Condition F is entered if a Steam Line Isolation - Manual channel is inoperable. Required Action F.1 requires the restoration of the inoperable channel in one hour, OR, per Required Action F.2.1, place the unit in MODE 3 in 7 hours AND, per Required Action F.2.2, place the unit in MODE 4 in 13 hours. This results in placing the unit in a MODE where the function is no longer required. This change imposes additional requirements on unit operation and is therefore more restrictive.	
	CTS:	**ITS:**
	15.03.05 T 15.03.05-04 02.D	LCO 3.03.02 COND F LCO 3.03.02 COND F RA F.1 LCO 3.03.02 COND F RA F.2.1 LCO 3.03.02 COND F RA F.2.2
M.08 Rev. F	CTS 15.4.1, Table 15.4.1-1, item 44, has been revised by the addition of MASTER RELAY TEST and SLAVE RELAY TEST surveillance requirements for ALL ESF Actuation logic (except Steam Line Isolation logic, which will only require a SLAVE RELAY TEST, and AFW Automatic Logic, which will require neither test, due to logic configuration). The Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment. The MASTER RELAY TEST will verify OPERABILITY of the master relays once per 18 months. The SLAVE RELAY TEST will verify the OPERABILITY of the slave relays and the required actuation devices. This change imposes additional requirements on unit operation and is more restrictive.	
	CTS:	**ITS:**
	NEW	SR 3.03.02.04 SR 3.03.02.05
M.09 Rev. E	Not used.	
	CTS:	**ITS:**
	N/A	N/A

DOC Number	DOC Text	
M.14 Rev. A	CTS Table 15.4.1-1 has been modified by the adoption of CHANNEL CHECK, COT and CHANNEL CALIBRATION surveillance requirements for the Pressurizer Pressure SI Block. This interlock enables the Pressurizer Pressure-Low and Steam Line Pressure- Low SI actuation signals above the Pressurizer Pressure SI Block setpoint. This safety function will be verified OPERABLE by the performance of a CHANNEL CHECK every 12 hours, a COT every 92 days and a CHANNEL CALIBRATION every 18 months. This change imposes additional requirements on unit operation and is more restrictive.	
	CTS:	**ITS:**
	NEW	SR 3.03.02.01 SR 3.03.02.03 SR 3.03.02.08
M.15 Rev. A	CTS Table 15.3.5-3 has been modified by the addition of item #4, Pressurizer Pressure SI Block. This item will provide the Limiting Condition for Operation for this Function. Adding this item to CTS Table 15.3.5-3 clarifies the MODES under which the interlock is required to be OPERABLE and provides Required Actions to take in the event of one or more inoperable channels. This change imposes additional requirements on unit operation and is more restrictive.	
	CTS:	**ITS:**
	NEW	LCO 3.03.02 COND I LCO 3.03.02 COND I RA I.1 LCO 3.03.02 COND I RA I.2.1 LCO 3.03.02 COND I RA I.2.2 LCO 3.03.02 T3.03.02-01 08
M.16 Rev. A	Table 15.4.1-1 has been modified by the addition of CHANNEL CHECK, COT and CHANNEL CALIBRATION surveillance requirements for the Steam Flow-High, Steam Flow-High High, and Tavg-Low instrumentation that provides signals to the Steam Line Isolation Function. These signals, coincident with an SI signal, provide closure of the MSIVs during a SLB or inadvertent opening of a relief or safety valve, to maintain at least one SG as a heat sink for the reactor, and limit the mass and energy released to the containment. Verification of the OPERABILITY of these functions will be through the performance of the CHANNEL CHECK, COT and CHANNEL CALIBRATION surveillances. This change imposes additional requirements on unit operation and is more restrictive.	
	CTS:	**ITS:**
	NEW	SR 3.03.02.01 SR 3.03.02.03 SR 3.03.02.08
M.17 Rev. F	Not used.	
	CTS:	**ITS:**
	N/A	N/A

DOC Number	DOC Text	
M.18 Rev. E	CTS 15.3.5, Table 15.3.5-3, Functions 1.a (Manual SI) and 3.b.i (AFW Turbine Driven Pump Start on Undervoltage Buses A01 and A02), and Table 15.3.5-4, Functions 1.b (Manual CI), 2.a (Hi Hi Steam Flow SLI), and 2.b (Hi Steam Flow SLI), have been revised to require additional channels to be operable. In the proposed ITS LCO 3.3.2, Table 3.3.2-1, the Manual SI Function will require 2 channels; AFW Actuation on Undervoltage Bus A01 and A02 Function will require 2 channels/each bus; the Manual CI Function will require 2 channels; the Hi Hi Steam Flow SLI Function will require 2 channels/loop; and the High Steam Flow SLI Function will require 2 channels/loop. Increasing the required number of channels for each of these functions imposes additional requirements on unit operation and is therefore more restrictive. This change is consistent with NUREG-1431.	
	CTS:	**ITS:**
	15.03.05 T 15.03.05-03 01.A	LCO 3.03.02 T3.03.02-01 01A
	15.03.05 T 15.03.05-03 03.B.I	LCO 3.03.02 T3.03.02-01 06D
	15.03.05 T 15.03.05-04 01.B	LCO 3.03.02 T3.03.02-01 03A
	15.03.05 T 15.03.05-04 02.A (1)	LCO 3.03.02 T3.03.02-01 04E-01
	15.03.05 T 15.03.05-04 02.B (1)	LCO 3.03.02 T3.03.02-01 04D-01
M.19 Rev. E	The Actions for an inoperable Manual SI channel have been revised. Because CTS only requires one of the two channels to be operable, when the channel becomes inoperable the unit is required to be in hot shutdown in 8 hours and cold shutdown in 48 hours. ITS requires 2 channels of Manual SI to be operable. The Required Actions for one inoperable channel have been adopted from NUREG-1431, requiring restoration of the channel to an operable status in 48 hours or be in MODE 3 in 54 hours and MODE 5 in 84 hours. If two channels of Manual SI are inoperable, LCO 3.0.3 shall be entered, requiring the unit to be in MODE 3 in 7 hours. Therefore, adopting the Required Actions of NUREG-1431 imposes additional requirements on unit operation and is more restrictive.	
	CTS:	**ITS:**
	15.03.05 T 15.03.05-03 01.A	LCO 3.03.02 COND B
		LCO 3.03.02 COND B RA B.1
		LCO 3.03.02 COND B RA B.2.1
	15.03.05 T 15.03.05-03 01.A*	LCO 3.03.02 COND B RA B.2.2

A.1

TABLE 15.3.5-1
(PAGE 1 OF 2)
ENGINEERED SAFETY FEATURES INITIATION INSTRUMENT SETTING LIMITS

NO.	FUNCTIONAL UNIT	CHANNEL	SETTING LIMIT	
1	High Containment Pressure (Hi)	Safety Injection*	≤ 6 psig	LCO 3.3.2, Table 3.3.2-1, #1.c
2	High Containment Pressure (Hi-Hi)	a. Containment Spray	≤ 30 psig	LCO 3.3.2, Table 3.3.2-1, #2.c
		b. Steam Line Isolation of Both Lines	≤ 20 psig	LCO 3.3.2, Table 3.3.2-1, #4.c
3	Pressurizer Low Pressure	Safety Injection*	≥ 1715 psig	LCO 3.3.2, Table 3.3.2-1, #1.d
4	Low Steam Line Pressure	Safety Injection*	≥ 500 psig	LCO 3.3.2, Table 3.3.2-1, #1.e
		Lead Time Constant	≥ 12 seconds	
		Lag Time Constant	≤ 2 seconds	
5	High Steam Flow in a Steam Line Coincident with Safety Injection and Low T_{AVG}	Steam Line Isolation of Affected Line	≤ d/p corresponding to 0.66 x 10^6 lb/hr at 1005 psig	LCO 3.3.2, Table 3.3.2-1, #4.d-1
			≥ 540°F	LCO 3.3.2, Table 3.3.2-1, #4.d-3
6	High-high Steam Flow in a Steam Line Coincident with Safety Injection	Steam Line Isolation of Affected Line	≤ d/p corresponding to 4 x 10^6 lb/hr at 806 psig	LCO 3.3.2, Table 3.3.2-1, #4.e-1
7	Low-low Steam Generator Water Level	Auxiliary Feedwater Initiation	≥20% of narrow range instrument A.3 ~~≥5% of narrow range instrument (Unit 1)**~~	LCO 3.3.2, Table 3.3.2-1, #6.b
8	Undervoltage on 4 KV Busses	Auxiliary Feedwater Initiation	≥ 3120 V	LCO 3.3.2, Table 3.3.2-1, #6.d

* Initiates also containment isolation, feedwater line isolation and starting of all containment fans.
~~** This setting limit applies to Unit 1 until the narrow range lower tap is changed to the lower position consistent with Unit 2~~
~~d/p means differential pressure~~

A.3

F
RAI 3.3.2-3

JFD Number	JFD Text
68 Rev. E	The NUREG-1431 Required Actions for an inoperable Manual Containment Spray initiation channel have been modified to require restoration of inoperable channel(s) in 1 hour, or be in MODE 3 in 7 hours and MODE 5 in 37 hours. This change is necessary due to PBNP design of the Manual Containment Spray initiation logic, which consists of two pushbuttons, both of which must be simultaneously depressed to actuate the two trains of Containment Spray. Therefore, one or both channels being inoperable results in a loss of function, requiring compensatory measures consistent with this condition. To provide these required actions, a new Condition E and associated Required Actions have been added. **ITS:** B 3.03.02; LCO 3.03.02 COND E; LCO 3.03.02 COND E RA E.1; LCO 3.03.02 COND E RA E.2.1; LCO 3.03.02 COND E RA E.2.2 **NUREG:** B 3.03.02; LCO 3.03.02 COND B; LCO 3.03.02 COND B RA B.1; LCO 3.03.02 COND B RA B.2.1; LCO 3.03.02 COND B RA B.2.2
69 Rev. F	The Allowable Value associated with the High SG Water Level – Feedwater Isolation function has been designated as "NA." No analytical limit or Allowable Value has been established for this function as it is not credited in the safety analysis for the mitigation of any accident. The High SG Water Level – Feedwater Isolation function provides backup FW Isolation for a reduction in feedwater enthalpy incident. A nominal setting is identified for this Function in the Bases. This nominal setting was developed outside of the setpoint methodology and have been provided by the NSSS supplier. **ITS:** B 3.03.02 **NUREG:** B 3.03.02
70 Rev. E	The time allowed to place an inoperable channel in the tripped condition has been changed from 6 hours to 1 hour. The 6 hour completion time of NUREG-1431, Required Action D.1 is based upon the analysis contained in WCAP-10271-P-A, Supplement 2. The SERs for WCAP-10271 require individual plants to confirm the applicability of the generic analysis of the WCAP. Point Beach Nuclear Plant has not confirmed the applicability of the generic analysis of WCAP-10271 and therefore, will retain the Completion Time requirements of the current licensing basis. This change also results in the revision of the Completion Times of Required Actions D.2.1 and D.2.2, such that the assumptions for completion of these required actions remain valid. **ITS:** LCO 3.03.02 COND D RA D.1; LCO 3.03.02 COND D RA D.2.1; LCO 3.03.02 COND D RA D.2.2 **NUREG:** LCO 3.03.02 COND D RA D.1; LCO 3.03.02 COND D RA D.2.1; LCO 3.03.02 COND D RA D.2.2

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP SETPOINT(a)~~
5. ~~Turbine Trip and~~ Feedwater Isolation							
a. Automatic Actuation Logic and Actuation Relays		1, 2(j), [3](j)	2 trains	~~H~~ [G] G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	~~NA~~
b. SG Water Level—High ~~High (P-14)~~		1, 2(j), [3](j)	[3] per SG 3	~~I~~ [D] D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≤ [84.2]% NA	~~≤ [82.4]%~~
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.						
6. Auxiliary Feedwater							
~~a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)~~		~~1,2,3~~	~~2 trains~~	~~G~~	~~SR 3.3.2.2~~ ~~SR 3.3.2.4~~ ~~SR 3.3.2.6~~	~~NA~~	~~NA~~
a b. Automatic Actuation Logic and Actuation Relays ~~(Balance of Plant ESFAS)~~		1,2,3	2 trains	G	SR 3.3.2.3 SR 3.3.2.2	NA	~~NA~~
b c. SG Water Level—Low Low		1,2,3	[3] per SG 3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ [30.4]% 20	~~≥ [32.2]%~~

(continued)

~~(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.~~

(j) (e) Except when all ~~MFIVs,~~ MFRVs, [and associated bypass valves] and associated bypass valves are closed and [de-activated] de-activated ~~[or isolated by a closed manual valve]~~.

F RAI 3.3.2-3

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. ~~Turbine Trip and~~ Feedwater Isolation – Steam Generator Water Level – High ~~High (P-14)~~ (continued)

instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic. For units that have dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements. For other units that have only three channels, a median signal selector is provided or justification is provided in NUREG-1218 (Ref. 7).

If this input to the SG Water Level Control System fails low, it would cause a control action to open the Feedwater Control Valve for the affected SG. The remaining channels, in a two-out-of-two configuration, would be required to detect a high SG Water level condition and initiate a Feedwater Isolation to prevent an overfill condition. Therefore, this configuration does not meet the single failure criteria of Reference 1. However, justification for a two-out-of-three Feedwater Isolation – SG Water Level – High Function is provided in NUREG-1218, Reference 5.

~~The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.~~

Table 3.3.2-1 identifies the Technical Specification Allowable Value for the Feedwater Isolation – SG Water Level – High function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Feedwater Isolation – SG Water Level – High function is 78% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.

c. ~~Turbine Trip and~~ Feedwater Isolation – Safety Injection

~~Turbine Trip and~~ Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

F

RAI 3.3.2-3

~~Turbine Trip and~~ Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 ~~[~~and 3~~]~~ except when all ~~MFIVs,~~ MFRVs, ~~[~~and associated bypass valves~~]~~ are closed and ~~[~~de-activated~~]~~ ~~[or isolated by a closed manual valve]~~ ~~when the MFW System is in operation and the turbine generator may be in operation.~~ In MODES ~~[3,]~~ 4, 5, and 6, the MFW System ~~and the turbine generator~~

Table 3.3.2-1 (page 3 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1,2(e),3(e)	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA
b. SG Water Level—High	1,2(e),3(e)	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2	NA
b. SG Water Level—Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≥ 20%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
d. Undervoltage Bus A01 and A02	1,2	2 per bus	H	SR 3.3.2.6 SR 3.3.2.8	≥ 3120 V
7. Condensate Isolation					
a. Containment Pressure—High	1,2(e),3(e)	3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 6 psig
b. Automatic Actuation Logic and Actuation Relays	1,2(e),3(e)	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	N/A
8. SI Block-Pressurizer Pressure	1,2,3	3	I	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 1800 psig

F RAI 3.3.2-3

(e) Except when all MFRVs and associated bypass valves are closed and de-activated.

F RAI 3.3.2-3

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

An SI signal results in the following actions:

- MFW pumps trip (causes subsequent closure of the MFW pump discharge valves); and
- MFRVs and the bypass regulating valves close.

A SG Water Level-High in either SG results in the closure of the MFRVs and the bypass regulating valves.

a. Feedwater Isolation-Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Feedwater Isolation-Steam Generator Water Level-High

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. If this input to the SG Water Level Control System fails low, it would cause a control action to open the Feedwater Control Valves for the affected SG. The remaining channels, in a two-out-of-two configuration, would be required to detect a high SG Water Level condition and initiate a Feedwater Isolation to prevent an overfill condition. Therefore this configuration does not meet the single failure criteria of Reference 1. However, justification for a two-out-of-three Feedwater Isolation-SG Water Level-High Function is provided in NUREG-1218, Reference 5.

Table 3.3.2-1 identifies the Technical Specification Allowable Value for the Feedwater Isolation – SG Water Level – High function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Feedwater Isolation – SG Water Level – High function is 78% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier. F RAI 3.3.2-3

c. Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 and 3 except when all MFRVs, and associated bypass valves are closed and de-activated. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST) (not safety related). Upon a low level in the CST, the operators can manually realign the pump suctions to the Service Water System, which is the safety related water source. The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater-Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink. A loss of MFW would result in a loss of SG water level. SG Water Level-Low Low in either SG will cause both motor driven pumps to start. The system is aligned so that upon start of the pumps, water immediately begins to flow to the SGs. SG Water Level-Low Low in both SGs will cause the turbine driven AFW pump to start.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

DOC Number	DOC Text	
L.07 Rev. A	The operator actions of CTS Table 15.3.5-5, item #28, Containment Isolation Position Indication, require an inoperable containment isolation valve shut position indication be restored in 7 days or close the valve or be in hot shutdown within the next 12 hours. Proposed ITS LCO 3.3.3, Condition A, is entered if one required channel is inoperable. Required Action A.1 requires restoration of the channel in 30 days, or per Condition B, submit a report in accordance with LCO 5.6.6, outlining the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status. The proposed actions to allow 30 days to restore the inoperable channel to OPERABLE status (instead of the current 7 day requirement) and the requirement to submit a report (in lieu of the shutdown requirements) are acceptable based on the low probability of an event requiring PAM instrumentation and the alternate means of monitoring the parameter. The alternate means must be established to utilize the provisions of the proposed actions.	
	CTS:	**ITS:**
	15.03.05 T 15.03.05-05 28	LCO 3.03.03 COND A
		LCO 3.03.03 COND A RA A.1
		LCO 3.03.03 COND B
		LCO 3.03.03 COND B RA B.1
L.08 Rev. A	The frequency of the Channel Check surveillance requirement for the following PAM instrumentation has been changed from Shiftly or Daily to Monthly (31 Days): Pressurizer Water Level; SG Water Level; SG Pressure; CST Level; Containment Hydrogen Monitor; and Containment Pressure. This change has been made to conform to NUREG-1431 and is consistent with the Channel Checks currently performed on other PAM instrumentation. The proposed frequency of 31 Days is adequate. The Channel Check supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.	
	CTS:	**ITS:**
	15.04.01 T 15.04.01-01 06	SR 3.03.03.01
	15.04.01 T 15.04.01-01 08	SR 3.03.03.01
	15.04.01 T 15.04.01-01 10	SR 3.03.03.01
	15.04.01 T 15.04.01-01 24	SR 3.03.03.01
	15.04.01 T 15.04.01-01 26.A	SR 3.03.03.01
	15.04.01 T 15.04.01-01 26.B	SR 3.03.03.01
	15.04.01 T 15.04.01-01 27	SR 3.03.03.01

DOC Number	DOC Text
L.09 Rev. F	CTS requires the Hydrogen Monitor Gas Calibration be performed using 2% and 6% sample gas. This information is a detail which is not necessary to describe the actual regulatory requirement, and is therefore not retained in ITS. This change is less restrictive, but is acceptable because the details are not necessary to provide adequate protection of the public health and safety, and the ITS still retains the requirement to perform the test. **CTS:** / **ITS:** 15.04.01 T 15.04.01-01 26.A (15) — N/A 15.04.01 T 15.04.01-01 NOTE (15) — N/A
LA.01 Rev. A	The information contained in CTS Table 15.3.5-5, "Total No. of Channels" column contains details of design which are not directly pertinent to describe the actual regulatory requirement. These details are not necessary to provide adequate protection of the public health and safety. This information has been moved to the FSAR. Changes to the FSAR will be controlled in accordance with the 10 CFR 50.59 process.

CTS:	ITS:
15.03.05 T 15.03.05-05 04	FSAR
15.03.05 T 15.03.05-05 06	FSAR
15.03.05 T 15.03.05-05 07	FSAR
15.03.05 T 15.03.05-05 09	FSAR
15.03.05 T 15.03.05-05 10	FSAR
15.03.05 T 15.03.05-05 11	FSAR
15.03.05 T 15.03.05-05 12	FSAR
15.03.05 T 15.03.05-05 13	FSAR
15.03.05 T 15.03.05-05 15	FSAR
15.03.05 T 15.03.05-05 16	FSAR
15.03.05 T 15.03.05-05 17	FSAR
15.03.05 T 15.03.05-05 18	FSAR
15.03.05 T 15.03.05-05 19	FSAR
15.03.05 T 15.03.05-05 20	FSAR
15.03.05 T 15.03.05-05 21	FSAR
15.03.05 T 15.03.05-05 22	FSAR
15.03.05 T 15.03.05-05 23	FSAR
15.03.05 T 15.03.05-05 24	FSAR
15.03.05 T 15.03.05-05 25	FSAR
15.03.05 T 15.03.05-05 26	FSAR
15.03.05 T 15.03.05-05 27	FSAR
15.03.05 T 15.03.05-05 28	FSAR

SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to Function 14 only. SR 3.3.3.3 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.4 applies to Function 12 only.

20

27

F

Errata #117

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.~~2~~ 3	~~-----------------NOTE----------------- Neutron detectors are excluded from CHANNEL CALIBRATION. -------------------------------------~~ Perform CHANNEL CALIBRATION.	~~18~~ [18] months

20

1

2

------------------------NOTE------------------------
CHANNEL CALIBRATION of Containment Area Radiation (High Range) detectors shall consist of a response to a source.

3

E

RAI 3.3.3-7

SR 3.3.3.2	Calibrate gas portion of Hydrogen Monitor.	92 days

20

27

SR 3.3.3.4	Perform TADOT.	18 months

BASES

LCO (continued)

15, 16, 17, 18

10 20, 21, 22, 23

Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and trend the ensuing core heatup. ~~The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of condensate runback in the hot legs, and nonuniform inlet temperatures.~~ Based on these evaluations, adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant ~~with two CETs per required channel. The CET pair are oriented radially to permit evaluation of core radial decay power distribution.~~ Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

8

8

F

Errata #182

25

Core Exit Temperature is used to control RCS pressure and temperature in the mitigation of a SGTR event.

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. ~~Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Therefore, two randomly selected thermocouples are not sufficient to meet the two thermocouples per channel requirement in any quadrant. The two thermocouples in each channel must meet the additional requirement that one is located near the center of the core and the other near the core perimeter, such that the pair of Core Exit Temperatures indicate the radial temperature gradient across their core quadrant. Unit specific evaluations in response to Item II.F.2 of NUREG-0737 (Ref. 3) should have identified the thermocouple pairings that satisfy these requirements. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.~~

8

BASES

20 27

SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to Function 14 only. SR 3.3.3.3 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.4 applies to Function 12 only.

F
Errata #117

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SURVEILLANCE REQUIREMENTS

--------------------NOTE--------------------
SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to Function 14 only. SR 3.3.3.3 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.4 applies to Function 12 only.

F Errata #117

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	Calibrate gas portion of the Hydrogen Monitors.	92 days
SR 3.3.3.3	----------NOTE---------- CHANNEL CALIBRATION of Containment Area Radiation (High Range) detectors shall consist of verification of a response to a source. ------------------------ Perform CHANNEL CALIBRATION.	18 months
SR 3.3.3.4	Perform TADOT.	18 months

E RAI 3.3.3-7

LCO (continued)

An evaluation was made of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and trend the ensuing core heatup. Based on these evaluations, adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant. Core Exit Temperature is used to control RCS pressure and temperature in the mitigation of a SGTR event.

F
Errata #182

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core.

24. Auxiliary Feedwater Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs.

The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 500 gpm. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs and verify AFW flow is isolated to a faulted SG;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is a Type A variable because operator action is required to throttle flow during an SLB accident to prevent the AFW pumps from operating in runout conditions. AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

BASES

ACTIONS (continued)

E.1

Condition E applies when the Required Action and associated Completion Time of Condition C or D are not met. Required Action E.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C or D, and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Conditions C or D are not met and Table 3.3.3-1 directs entry into Condition F, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

G.1

Alternate means of monitoring Containment Area Radiation have been developed and tested. These alternate means may be used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.6, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

E Errata #11

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to Function 14 only. SR 3.3.3.3 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.4 applies to Function 12 only.

F Errata #117

Insert 3.3.7-1 (continued):

Table 3.3.5-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Control Room Radiation				
a. Control Room Area Monitor	1, 2, 3, 4, (a), (b)	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.3	NA
b. Control Room Air Intake	1, 2, 3, 4, (a), (b)	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.3	NA
2. Containment Isolation	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 3, for all initiation functions and requirements.			

(a) During movement of irradiated fuel assemblies.

(b) During CORE ALTERATIONS.

F RAI 3.3.7-2

F RAI 3.3.7-2

JFD Number	JFD Text	
07 Rev. A	The Bases for NUREG 1431 LCO 3.3.7 has been modified to reflect the CREFS actuation instrumentation design. As addressed in Justification for Deviation 1 of this LCO, the Point Beach CREFS actuation instrumentation consists of a Containment Isolation signal, a single control room area monitor and a single intake noble gas monitor.	
	ITS:	**NUREG:**
	B 3.03.05	B 3.03.07
08 Rev. A	Based on having only a single channel per function (radiation monitor), the Bases for NUREG 1431 SR 3.3.7.1, Channel Check, has been rewritten to clarify method of performance. As provided in the Definition of Channel Check, a Channel Check can be a qualitative assessment by observation of channel behavior. Where possible, a Channel Check should include a comparison of channel indication and status to other status derived from independent instrument channels. In the Case of these monitors, no independent instrument channel exist; therefore, the Channel Check will consist of a qualitative assessment of expected behavior based on plant and control room conditions.	
	ITS:	**NUREG:**
	B 3.03.05	B 3.03.07
09 Rev. F	Not used.	
	ITS:	**NUREG:**
	B 3.03.05	B 3.03.07
	LCO 3.03.05 T3.03.05-01 01B	LCO 3.03.07 T3.03.07-01 03B
10 Rev. A	Any or all of the actuation functions are allowed to be inoperable for 7 days, which is consistent with the allowed outage time of the control room ventilation system. Therefore, the basis information pertaining to channel inoperability has been appropriately modified to account for the inoperability of entire functions, rather than channels.	
	ITS:	**NUREG:**
	B 3.03.05	B 3.03.07

JFD Number	JFD Text	
11 Rev. A	NUREG 1431 LCO 3.3.4, Remote Shutdown System, has not been adopted as part of Point Beach's conversion to the Improved Technical Specifications. The Point Beach CTS does not contain any Specifications which would require operability of instrumentation or controls associated with the capability to remotely shutdown the units. By not adopting this specification, subsequent LCOs are renumbered.	
	ITS:	**NUREG:**
	B 3.03.05	B 3.03.07
	LCO 3.03.05	LCO 3.03.07
	LCO 3.03.05 T3.03.05-01	LCO 3.03.07 T3.03.07-01
	SR 3.03.05.01	SR 3.03.07.01
	SR 3.03.05.02	SR 3.03.07.02
	SR 3.03.05.03	SR 3.03.07.07
12 Rev. F	The Trip Setpoints associated with the Control Room Area Monitor and Control Room Air Intakes have been designated as "NA." No analytical limits or Allowable Values have been established for these functions as they are not credited in the safety analysis for the mitigation of any accident. Nominal settings for these Functions are identified in the Bases. These nominal settings were developed outside of the setpoint methodology.	
	ITS:	**NUREG:**
	LCO 3.03.05 T3.03.05-01	LCO 3.03.07 T3.03.07-01
	LCO 3.03.05 T3.03.05-01 NOTE (c)	N/A

Approved TSTF-161

11 → 5

Table 3.3.7-1 (page 1 of 1)
CREFS Actuation Instrumentation

11 → 5

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation		~~2 trains~~	SR 3.3.7.6	NA
2. Automatic Actuation Logic and Actuation Relays		2 trains	SR 3.3.7.3 SR 3.3.7.4 SR 3.3.7.5	NA
~~3.~~ 1. Control Room Radiation Area Monitor				
a. Control Room Atmosphere	1, 2, 3, 4, ~~[5, 6,]~~ (a), [(b)]	[2] 1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.~~7~~	≤ [2] mR/hr NA
b. Control Room Air Intakes		[2] 1	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.~~7~~	≤ [2] mR/hr
~~4.~~ 2. ~~Safety Injection~~ Containment Isolation	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function ~~1.~~ 3 for all initiation functions and requirements.			

Approved TSTF-161

(a) During movement of irradiated fuel assemblies.
~~(~~b) During CORE ALTERATIONS.~~)~~

4 5 1 3 1 6 11 5 3 12 6 3

RAI 3.3.7-2

RAI 3.3.7-2

LCO 3.3.5 BASES INSERTS

Insert B 3.3.5-3:

The LCO requires the control room area (RE-101) and the control room air intake noble gas monitor (RE-235) to be OPERABLE, to ensure that the instrumentation necessary to initiate the CREFS emergency make-up mode (Mode 4) is OPERABLE.

Table 3.3.5-1 identifies the Technical Specification Trip Setpoint for the Control Room Area Monitor and Control Room Air Intakes as not applicable (NA). No Analytical Value is assumed in the accident analysis for these functions. The nominal setting required for the Control Room Area Monitor is 5 mr/hr and the nominal setting for the Control Room Air Intakes is 5E-5 μCi/cc. These nominal settings were developed outside of the setpoint methodology.

F

RAI 3.3.7-2

Insert B 3.3.5-4:

Condition A applies to the containment isolation signal, the control room area radiation monitor (RE-101) and the control room intake noble gas monitor (RE-235).

If a Function is inoperable, 7 days is permitted to restore the Function to OPERABLE status from the time the Condition was entered for that Function. The 7 day Completion Time is the same as for inoperable CREFS. The basis for this Completion Time is the same as provided in LCO 3.7.9. If the monitor cannot be restored to OPERABLE status, CREFS must be placed in the emergency make-up mode of operation (Mode 4). Placing CREFS in the emergency make-up mode of operation accomplishes the actuation instrumentation's safety function.

Table 3.3.5-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Control Room Radiation				
a. Control Room Area Monitor	1, 2, 3, 4, (a), (b)	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.3	NA
b. Control Room Air Intake	1, 2, 3, 4, (a), (b)	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.3	NA
2. Containment Isolation	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 3, for all initiation functions and requirements.			

(a) During movement of irradiated fuel assemblies.

(b) During CORE ALTERATIONS.

F RAI 3.3.7-2

F RAI 3.3.7-2

B 3.3 INSTRUMENTATION

B 3.3.5 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

BASES

BACKGROUND

The CREFS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. The control room ventilation system normally operates in the normal operating mode (Mode 1). Upon receipt of an actuation signal, the CREFS initiates the emergency make-up (Mode 4) mode of operation. The control room ventilation system and its operating modes are described in the Bases for LCO 3.7.9, "Control Room Emergency Filtration System."

The actuation instrumentation consists of containment isolation, noble gas radiation monitor in the air intake and control room area radiation monitor. A containment isolation signal or high radiation signal from either of these detectors will initiate the emergency make-up mode of operation (Mode 4) of the CREFS.

APPLICABLE SAFETY ANALYSES

The CREFS provides airborne radiological protection for control room personnel, as demonstrated by the limiting control room dose analyses for the design basis large break loss of coolant accident. Control room dose analysis assumptions are presented in the FSAR, Section 14.3.5 (Ref. 1).

In MODES 1, 2, 3, and 4, a containment isolation signal or the CREFS radiation monitor actuation signal will provide automatic initiation of CREFS in the emergency make-up mode of operation (Mode 4) during design basis events which result in significant radiological releases to the environs (e.g. large break loss of coolant accident, steam generator tube rupture, reactor coolant pump locked rotor, etc;).

The CREFS radiation monitor actuation signal also provides automatic initiation of CREFS, in the emergency make-up mode of operation (Mode 4), to assure control room habitability in the event of a fuel handling during movement of
irradiated fuel, and CORE ALTERATIONS.

Further Applicable Safety Analysis information for CREFS is contained in the Bases for LCO 3.7.9, "Control Room Emergency Filtration System."

The CREFS actuation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

BASES

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREFS is OPERABLE.

1. Control Room Radiation

The LCO requires the control room area (RE-101) and the control room air intake noble gas monitor (RE-235) to be OPERABLE, to ensure that the instrumentation necessary to initiate the CREFS emergency make-up mode (Mode 4) is OPERABLE.

Table 3.3.5-1 identifies the Technical Specification Trip Setpoint for the Control Room Area Monitor and Control Room Air Intakes as not applicable (NA). No Analytical Value is assumed in the accident analysis for these functions. The nominal setting required for the Control Room Area Monitor is 5 mr/hr and the nominal setting for the Control Room Air Intakes is 5E-5 μCi/cc. These nominal settings were developed outside of the setpoint methodology. F RAI 3.3.7-2

2. Containment Isolation

Refer to LCO 3.3.2, Function 3, for all initiating Functions and requirements.

APPLICABILITY

The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, and during CORE ALTERATIONS and movement of irradiated fuel assemblies.

The Applicability for the CREFS actuation on the ESFAS Safety Injection Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Safety Injection Function Applicability.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.5-1 in the accompanying LCO. The Completion Time(s) of the inoperable Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the containment isolation signal, control room area radiation monitor (RE-101) and the control room intake noble gas monitor (RE-235).

If a Function is inoperable, 7 days is permitted to restore the Function to

BASES

ACTIONS (continued)

OPERABLE status from the time the Condition was entered for that Function. The 7 day Completion Time is the same as for inoperable CREFS. The basis for this Completion Time is the same as provided in LCO 3.7.9. If the Function cannot be restored to OPERABLE status, CREFS must be placed in the emergency make-up mode of operation (MODE 4). Placing CREFS in the emergency make-up mode of operation accomplishes the actuation instrumentation's safety function.

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

Condition B applies when the Required Action and associated Completion Time for Condition A have not been met. If Movement of irradiated fuel assemblies or CORE ALTERATIONS are in progress, these activities must be suspended immediately to reduce the risk of accidents that would require CREFS actuation. In addition, if any unit is in MODE 1, 2, 3, or 4, the unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions for Condition B are modified by a Note that states that Required Actions B.1 and B.2 are not applicable for inoperability of the Containment Isolation actuation function. This note is necessary because the Applicability for the Containment Isolation actuation function is Modes 1, 2, 3, and 4. The Containment Isolation actuation function is not used for mitigation of accidents involving the movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.5-1 determines which SRs apply to which CREFS Actuation Functions.

SR 3.3.5.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. However, in the case of the control room area and control room intake noble gas monitors, no independent instrument channel exist, therefore, the CHANNEL CHECK for these monitors will consist of a qualitative assessment of expected channel behavior, based on current plant and control room conditions. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues

BASES

SURVEILLANCE REQUIREMENTS (continued)

to operate properly between each CHANNEL CALIBRATION. The Frequency is based on operating experience that demonstrates channel failure is rare.

SR 3.3.5.2

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREFS actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

SR 3.3.5.3

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor.
The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

FSAR. Section 14.3.5.

Description of Changes - NUREG-1431 Section 3.04.07

09-May-01

DOC Number	DOC Text
L.02 Rev. A	The CTS is revised by adopting ITS LCO 3.4.7, Note 1. This Note permits the RHR pump of the loop in operation to not be in operation for up to 1 hour in any 8 hour period, to permit tests that are designed to validate various accident analyses values. The allowance for no RHR pump to be in operation is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because such an operation would be performed as part of a special test, and be controlled under close scrutiny by shift operating personnel. In addition, the allowances of the Note may only be used if no operations which could cause a reduction of RCS boron concentration are being performed and core outlet temperature is maintained at least 10 °F below saturation temperature. Industry operating experience has also shown that boron stratification is not a problem during this short period with no forced flow. Natural circulation provides adequate heat removal in this condition during the limited time period in the Note. **CTS:** NEW **ITS:** LCO 3.04.07 NOTE 1; LCO 3.04.07 NOTE 1A; LCO 3.04.07 NOTE 1B
L.03 Rev. F	The CTS is revised by adopting ITS LCO 3.4.7, Note 4. This Note provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup, by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note also allows the RHR loops to be removed from service, when at least one RCS loop is in operation, to perform leakage or flow testing. This is necessary, because the Point Beach RHR System configuration requires the RHR System to be removed from service to perform the leakage test. This Note results in a relaxation of the CTS requirements by allowing an RCS loop to be in operation and replace the RCS circulation function provided by the RHR loops below 140 °F. This change is acceptable, because the CTS lower limit of 140 °F is an arbitrary number based on refueling operations. During refueling operations, the RCS loops may, or may not, be filled. ITS LCO 3.4.7 applies in MODE 5 with the RCS loops filled. Therefore, allowing the use of RCS loop(s) for decay heat removal below 140 °F is acceptable. **CTS:** NEW **ITS:** LCO 3.04.07 NOTE 4
LA.01 Rev. A	The value of the LTOP enabling temperature is removed from the Specifications and placed in the Pressure Temperature Limits Report (PTLR). This information provides details of design or process that are not directly pertinent to the actual requirement, i.e., Limiting Condition for Operation or Surveillance Requirement, but rather describe frequently changing parameters of the specification. This detail is not necessary to adequately describe the actual regulatory requirement, and can be moved to licensee controlled documents without a significant impact on safety. Administrative controls are included in Section 5 of the proposed ITS to control revisions to these values. **CTS:** 15.03.15.B.02 **ITS:** LCO 3.04.07 NOTE 3

Section 3.4.7 CTS Markup Inserts

Insert 3.4.7-1:

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

A.4

a. One additional RHR loop shall be OPERABLE; or

L.1

b. The secondary side water level of at least one steam generator (SG) shall be ≥ 30% narrow range.

NOTES

1. The RHR pump of the loop in operation may be not in operation for ≤ 1 hour per 8 hour period provided:

L.2

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least 10 °F below saturation temperature.

M.2

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

B
RAI 3.4.7-1

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ Low Temperature Overpressure Protection (LTOP) enabling temperature specified in the PTLR unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

LA.1

L.3

4. All RHR loops may be removed from operation during planned heatup to MODE 4 or during the performance of required leakage or flow testing when at least one RCS loop is in operation.

F
Errata #172

APPLICABILITY: MODE 5 with RCS loops filled.

M.1

Justification For Deviations - NUREG-1431 Section 3.04.07

09-May-01

JFD Number	JFD Text	
05 Rev. B	Not Used.	
	ITS:	**NUREG:**
	B 3.04.07	B 3.04.07
	N/A	N/A
06 Rev. A	The wording of the LCO 3.4.7 Note and Bases was changed from "...may be de-energized..." to "...may not be in operation...", per approved TSTF 153. However, "...may not be in operation..." could easily be interpreted to imply a condition that forbids RCP operation. To prevent this misunderstanding, the wording has been changed to, "...may be not in operation..."	
	ITS:	**NUREG:**
	B 3.04.07	B 3.04.07
	LCO 3.04.07 NOTE 1	LCO 3.04.07 NOTE 1
07 Rev. A	"Narrow range" was added to the description of the required secondary side water level of the steam generators. NUREG-1431 did not specify a level indication instrumentation reference for the steam generator water level. To avoid possible interpretation, "narrow range" was added to specify that the required steam generator water level percentage is indicated narrow range. 30% narrow range level indication is a much higher water level (i.e. more conservative) than 30% wide range indication and ensures that the steam generator tubes are covered.	
	ITS:	**NUREG:**
	B 3.04.07	B 3.04.07
	LCO 3.04.07 B	LCO 3.04.07 B
	SR 3.04.07.02	SR 3.04.07.02
08 Rev. F	An allowance is being added to LCO 3.4.7 NOTE 4 and the applicable Bases to allow both RHR loops to be removed from operation when at least one RCS loop is in operation to allow for the performance of leakage or flow testing. The CTS allows reactor coolant loops for decay heat removal when the RCS temperature is > 140 °F and < 350 °F in accordance with CTS 15.3.1.A.3.a(1). This allowance is necessary based on the design of the Point Beach RHR System configuration, which requires the system to be removed from service to perform the required PIV leakage testing.	
	ITS:	**NUREG:**
	B 3.04.07	B 3.04.07
	LCO 3.04.07 NOTE 4	LCO 3.04.07 NOTE 4

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops – MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

7

narrow range

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least [two] steam generator~~s~~ (SG~~s~~) shall be ≥ [17]%.

1 30 1 one

Approved TSTF-153

------------------------------NOTES------------------------------

1. The RHR pump of the loop in operation may ~~be~~ de-energized for ≤ 1 hour per 8 hour period provided:

Approved TSTF-153

not be in operation

be not in operation

6

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least 10 °F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

B
RAI 3.4.7-1

2

Low Temperature Overpressure Protection (LTOP) enabling temperature specified in the PTLR.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ [275]°F unless the secondary side water temperature of each SG is ≤ [50]°F above each of the RCS cold leg temperatures.

50 1

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

----

8 or during the performance of required leakage or flow testing

F
Errata #172

APPLICABILITY: MODE 5 with RCS loops filled.

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10 °F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

2

Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

B
RAI 3.4.7-1

1 50

Note 3 requires that the secondary side water temperature of each SG be ≤ [50] °F above each of the RCS cold leg temperatures before the start of a reactor ~~coolant pump~~ (RCP) with an RCS cold leg temperature ≤ [275] °F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 also allows both RHR loops to be removed from operation when at least one RCS loop is in operation to allow for the performance of leakage or flow testing, as required by Technical Specifications or by regulation. This allowance is necessary based on the design of the Point Beach RHR System configuration, which requires the system to be removed from service to perform the required PIV leakage testing.

8

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

F
Errata #172

via natural circulation (Ref. 1)

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink ~~when it has an adequate water~~ level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

Approved TSTF-114

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE,

NSHC Number	NSHC Text
L.03 Rev. F	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. This change results in adopting ITS LCO 3.4.7, Note 4. This Note provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup, by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note also allows the RHR loops to be removed from service, when at least one RCS loop is in operation, to perform leakage or flow testing. This is necessary, because the Point Beach RHR System configuration requires the RHR System to be removed from service to perform the testing. This Note results in a relaxation of the CTS requirements by allowing an RCS loop to be in operation and replace the RCS circulation function provided by the RHR loops below 140 °F. This change is acceptable, because the CTS lower limit of 140 °F is an arbitrary number based on refueling operations. During refueling operations, the RCS loops may, or may not, be filled. ITS LCO 3.4.7 applies in MODE 5 with the RCS loops filled. Therefore, allowing the use of RCS loop(s) for decay heat removal below 140 °F is acceptable. Therefore, this change does not involve an 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? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation or alter the method of normal plant operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? There are no margins of safety related to safety analyses that are dependent upon the proposed change. The requirements will continue to assure that limiting conditions for the RCS are properly maintained. Therefore, this change does not involve a reduction in a margin of safety.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops—MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least one steam generator (SG) shall be ≥ 30% narrow range.

-----------------------------------NOTES-----------------------------------

1. The RHR pump of the loop in operation may be not in operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation. B RAI 3.4.7-1

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 or during the performance of required leakage or flow testing when at least one RCS loop is in operation. F Errata #172

APPLICABILITY: MODE 5 with RCS loops filled.

BASES

LCO (continued)

temperature ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops. Note 4 also allows both RHR loops to be removed from operation when at least one RCS loop is in operation to allow for the performance of leakage or flow testing, as required by Technical Specifications or by regulation. This allowance is necessary based on the design of the Point Beach RHR System configuration, which requires the system to be removed from service to perform the required PIV testing. F Errata #172

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink via natural circulation (Ref. 1) when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes.

However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least one SGs is required to be ≥ 30% narrow range.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

level alarm 1

a. One containment sump (level or discharge flow) monitor;

and

b. One containment atmosphere radioactivity monitor (gaseous or particulate); ~~[and~~

~~c. One containment air cooler condensate flow rate monitor].~~ 2

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required containment sump monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	A.1 Perform SR 3.4.13.1.	Once per 24 hours
	AND	
	A.2 Restore required containment sump monitor to OPERABLE status.	30 days

(continued)

level alarm 1

F Errata #147

------------NOTE------------
Not required until 12 hours after establishment of steady state operation.

Approved TSTF-116 R.2

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~D. Required containment atmosphere radioactivity monitor inoperable.~~ ~~AND~~ ~~Required containment air cooler condensate flow rate monitor inoperable.~~	~~D.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status.~~ ~~OR~~ ~~D.2 Restore required containment air cooler condensate flow rate monitor to OPERABLE status.~~	~~30 days~~ ~~30 days~~
E. C Required Action and associated Completion Time not met.	E.1 C Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours
F. D All required monitors and level alarm inoperable.	F.1 D Enter LCO 3.0.3.	Immediately

2

1

Errata #147

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.15.1 Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	12 hours

(continued)

APPLICABLE SAFETY ANALYSES (continued)

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

1 level alarm

F Errata #147

The LCO is satisfied when ~~monitors of~~ diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor ~~[and a containment air cooler condensate flow rate monitor]~~, provides an acceptable minimum.

2

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

level alarm 1

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1,

ACTIONS (continued)

required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

2 D

F 1

and the level alarm 1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

F Errata #147

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

4 ~~SR 3.4.15.2~~

~~SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.~~

4 SR 3.4.15.2 and SR 3.4.15.3 2

SR 3.4.15.3, [SR 3.4.15.4 ~~and SR 3.4.15.5]~~

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of [18] months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

2 18

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One containment sump level alarm; and

b. One containment atmosphere radioactivity monitor (gaseous or particulate).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required containment sump level alarm inoperable.	-----------------NOTE----------------- LCO 3.0.4 is not applicable. --	
	----------NOTE----------- Not required until 12 hours after establishment of steady state operation. ----------------------------	
	A.1 Perform SR 3.4.13.1.	Once per 24 hours
	AND	
	A.2 Restore required containment sump monitor to OPERABLE status.	30 days

F Errata #147

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere radioactivity monitor inoperable.	-----------------NOTE--------------- LCO 3.0.4 is not applicable. -------------------------------------	
	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	----------NOTE---------- Not required until 12 hours after establishment of steady state operation. ---------------------------	
	B.1.2 Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status.	30 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	C.2 Be in MODE 5.	36 hours
D. All required monitors and level alarm inoperable.	D.1 Enter LCO 3.0.3.	Immediately

F
Errata #147

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

FSAR, Section 1.3.3 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE is instrumented to alarm when water in the sump reaches a pre-determined level. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-8} μCi/cc radioactivity for particulate monitoring and of 10^{-7} μCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

BASES

BACKGROUND (continued)	Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in the containment sump level. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO. Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Temperature and pressure monitors are not required by this LCO.
APPLICABLE SAFETY ANALYSES	The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the FSAR (Ref. 3). The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public. RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.
LCO	One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation. The LCO is satisfied when diverse measurement means are available. Thus, the containment sump level alarm, in combination with a gaseous or particulate radioactivity monitor provides an acceptable minimum. F Errata #147

BASES

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump level alarm inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (i.e., stable temperature, power level, pressurizer and VCT levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required sump level alarm to OPERABLE status within a Completion Time of 30 days is required to regain the function after the alarm's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

Required Action A.1 is modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the containment sump level alarm is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

BASES

ACTIONS (continued) B.1.1, B.1.2, and B.2.1

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors. The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (i.e., stable temperature, power level, pressurizer and VCT levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

Required Action B.1 and Required Action B.2 are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the gaseous and particulate containment atmosphere radioactivity monitor channel is inoperable. This allowance is provided because other instrumentation is available to monitor for RCS LEAKAGE.

C.1 and C.2

If a Required Action of Condition A or B cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

With all required monitors and the level alarm inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required. F Errata #147

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2 and SR 3.4.15.3

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

REFERENCES

1. FSAR Section 1.3.3.

2. FSAR, Section 6.5.

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
A.01 Rev. A	In the conversion of Point Beach current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the Standard Technical Specifications, Westinghouse Plants, NUREG-1431, Revision 1 (i.e., Improved Standard Technical Specifications (ISTS)).

CTS:	ITS:
15.03.03.A.02	LCO 3.05.02 COND B LCO 3.05.02 COND B RA B.1
15.03.03.A.03	LCO 3.05.02 COND B LCO 3.05.02 COND B RA B.1
15.04.05	LCO 3.05.02
15.04.05.I.A.02	SR 3.05.02.03 SR 3.05.02.04

DOC Number	DOC Text
A.02 Rev. A	The CTS states that the ECCS systems and components listed in Specification 15.3.3.A.1.c, f, and g (SI pumps, SI discharge isolation valves, associated valves, interlocks, and piping) are required to be operable prior to the reactor being made critical. However, the Actions contained in CTS 15.3.3.A.2 will place the unit in cold shutdown if the SI pump/subsystem is not returned to an operable status within its allowed out of service time, implying an Applicability of Modes 1, 2, 3, and 4 (ITS Modes). CTS 15.3.15.B modifies the requirement of CTS 15.3.3.A.1.c (required number of SI pumps) by stating that one of the two high head Safety Injection pumps are to be rendered inoperable whenever LTOP is required (less than 355 degrees). Proposed LCO 3.5.2 requires two trains of ECCS (SI and an RHR subsystem) to be operable in Modes 1, 2, and 3 (greater than or equal to 350 degrees) and allows one of the two SI pumps to be inoperable under specific constraints (up to four hours after entry into Mode 3 or until all RCS cold leg temperatures exceed 375 degrees, whichever comes first). As such, in Modes 1, 2, and 3 when RCS temperature is greater than or equal to 355 degrees, the number of required SI pumps/subsystems is the same in the proposed ITS as the CTS. The four hour and 375 degree SI pump restoration/disablement constraints are discussed in Description of Changes M.2 and L.1 of this section. The Mode 4 ECCS aspects of this LCO are discussed in LCO section 3.5.3.

CTS:	ITS:
15.03.03.A.01	LCO 3.05.02

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
A.03 Rev. A	CTS 15.3.3.A.1.c and d require two safety injection (SI) and two residual heat removal (RHR) pumps to be operable, while CTS 15.4.2.B.3 and CTS 15.4.5.II.A.1 requires these pumps to be tested in accordance with ASME Section XI. ITS LCO 3.5.2 requires two ECCS trains to be operable, and ITS SR 3.5.2.2 requires each ECCS pump to be tested in accordance with the Inservice Testing Program. Accordingly, while presented in a different fashion than the CTS, the ITS continue to require two SI and RHR pumps to be operable, and require both SI and RHR pumps to be testing in accordance with the ASME code. **CTS:** / **ITS:** 15.03.03.A.01.C — SR 3.05.02.02 15.03.03.A.01.D — SR 3.05.02.02 15.04.02.B.03 — SR 3.05.02.02 15.04.05.II.A.01 — SR 3.05.02.02
A.04 Rev. F	CTS 15.3.3.A.1.f requires the isolation valves in the discharge header of the SI system to be in the open position. ITS SR 3.5.2.1 requires each manual, power operated and automatic valve in the ECCS flowpath, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position at least once every 31 days. All surveillance requirements associated with an LCO are required to be met in order to fulfill the LCO. Accordingly, there is no change in requirement, making this change administrative. **CTS:** / **ITS:** 15.03.03.A.01.F — SR 3.05.02.01
A.05 Rev. A	CTS 15.3.3.A.1.g, requires the interlocks associated with the ECCS pumps and valves which are required to function during accident conditions to be operable. CTS 15.4.5.I.A.1 requires the performance of a system test during reactor shutdowns for major refueling outages, which ultimately verifies that all components received their actuation signal and actuate to their correct positions. ITS SR 3.5.2.3 requires each ECCS automatic valve in the flowpath that is not locked, sealed, or otherwise secured in position, to be tested to ensure it actuates to its correct position on an actual or simulated actuation signal. Similarly, SR 3.5.2.4 requires each ECCS pump to be tested to ensure it actuates on an actual or simulated actuation signal. Accordingly, both the CTS and ITS require these attributes, making this change administrative, consistent with the format and presentation of NUREG 1431. **CTS:** / **ITS:** 15.03.03.A.01.G — SR 3.05.02.03 SR 3.05.02.04

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
A.06 Rev. A	CTS 15.3.3.A.2.b, 15.3.3.A.2.c, 15.3.3.A.3.a, and 15.3.3.A.3.c allow 72 hours to restore an inoperable SI pump, RHR pump, or valve affecting an SI or RHR subsystem to operable status providing the redundant pumps and valves are operable. ITS LCO 3.5.2 Condition A allows 72 hours for an ECCS Train to be returned to operable status, prior to requiring a unit shutdown. The CTS verbiage requiring the redundant pumps and valves have been omitted as this requirement is inherent to Condition A which only provides Actions for a single inoperable ECCS Train. Accordingly, the CTS and ITS requirement are the same, making this change administrative.

CTS:	ITS:
15.03.03.A.02.B	DELETED
15.03.03.A.02.C	DELETED
15.03.03.A.03.A	DELETED
15.03.03.A.03.C	DELETED

DOC Number	DOC Text
A.07 Rev. A	CTS 15.3.3.A.2.b, 15.3.3.A.2.c, 15.3.3.A.3.a, 15.3.3.A.3.b, and 15.3.3.A.3.c, define components within the safety injections and residual heat removal systems which are allowed to be inoperable for up to 72 hours before requiring a unit shutdown. Similarly, ITS LCO 3.5.2 Condition A and Required Action A.1 allows one train of ECCS to be inoperable for up to 72 hours before requiring a unit shutdown. The CTS details which define the components that may be inoperable (pumps, valves, and heat exchangers) are attributes of an ECCS Train which are addressed by the Surveillance Requirements associated with LCO 3.5.2, or by the definition of operability. The inoperability of an ECCS Train's component which results in a train of ECCS becoming inoperable, requires entry into Condition A. Therefore, these details are not necessary to define the entry conditions for the ITS Condition and can be removed from the Technical Specifications without changing the meaning, usage, or intent of this Condition.

CTS:	ITS:
15.03.03.A.02.B	LCO 3.05.02 COND A RA A.1
15.03.03.A.02.C	LCO 3.05.02 COND A RA A.1
15.03.03.A.03.A	LCO 3.05.02 COND A LCO 3.05.02 COND A RA A.1
15.03.03.A.03.B	LCO 3.05.02 COND A LCO 3.05.02 COND A RA A.1
15.03.03.A.03.C	LCO 3.05.02 COND A LCO 3.05.02 COND A RA A.1

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text	
A.08 Rev. A	The Bases of the current Technical Specifications for this LCO have been completely replaced by the revised Bases reflecting the format and applicable content of the Improved Technical Specifications for Point Beach. The proposed Bases are based on NUREG 1431 Rev. 1. The proposed Bases for this LCO are consistent and supportive of the proposed LCO, and accordingly is administrative.	
	CTS:	**ITS:**
	BASES	B 3.05.02
A.09 Rev. A	CTS 15.4.5.II.A.1 requires the SI and RH pumps to be tested in accordance with the Inservice Testing Program, while CTS 15.4.5.II.A.2 specifies that the pumps must start and reach their required developed head on the full flow test line. ITS SR 3.5.2.2 requires the SI and RH pumps to be tested in accordance with the Inservice Testing Program, and that the pumps develop greater than or equal to their required head at the test flow point. The CTS requirement only states to use the full flow test line not a specific test configuration/point. Accordingly, the CTS and the ITS item are the same, making this change administrative.	
	CTS:	**ITS:**
	15.04.05.II.A.02	SR 3.05.02.02
A.10 Rev. A	The CTS provides an introductory statement (Applicability) which simply states which systems/components are addressed within a given section. This same information while worded differently is contained within the title of each ITS LCO. Accordingly, this change is a change in format with no change in technical requirement.	
	CTS:	**ITS:**
	15.03.03 APPL	LCO 3.05.02
	15.04.05 APPL	LCO 3.05.02
A.11 Rev. A	The CTS provides an introductory statement (Objective) at the beginning of this Section of the Technical Specifications which provide a brief summary of the purpose for this Section. This information is contained in the Bases Section of the ITS. This information does not establish any regulatory requirements for the systems and components addressed within this Section. Accordingly, deletion of this information does not alter any requirement set forth in the Technical Specifications. This change is administrative and consistent with the format and presentation for the ITS as provided in NUREG 1431.	
	CTS:	**ITS:**
	15.03.03 OBJ	B 3.05.02
	15.04.05 OBJ	B 3.05.02

DOC Number	DOC Text
L.01 Rev. A	The CTS states that the ECCS systems and components listed in Specification 15.3.3.A.1.c, f, and g (SI pumps, SI discharge isolation valves, associated valves, interlocks, and piping) are required to be operable prior to the reactor being made critical. However, the Actions contained in CTS 15.3.3.A.2 will place the unit in cold shutdown if the SI pump/subsystem is not returned to an operable status within its allowed out of service time, implying an Applicability of Modes 1, 2, 3, and 4 (ITS Modes). CTS 15.3.15.B modifies the requirement of CTS 15.3.3.A.1.c (required number of SI pumps) by stating that one of the two high head Safety Injection pumps to be rendered inoperable whenever LTOP is required (less than 355 degrees). The ECCS flow paths consist of piping, valves, heat exchangers, and pumps necessary to provide water from the RWST into the RCS during the injection phase and from the containment sump into the RCS during the recirculation phase following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, heat exchangers, and the SI pumps. Each of the two subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. Proposed LCO 3.5.2 requires two trains of ECCS (SI and an RHR subsystem) to be operable in Modes 1, 2, and 3 (greater than or equal to 350 degrees); allows both SI flow pump flow paths to be isolated in order to perform pressure isolation valve testing (up to two hours); and, allows one of the two SI pumps to be incapable of injection under specific constrains (up to four hours after entry into Mode 3 or until all RCS cold leg temperatures exceed 375 degrees, whichever comes first). In Modes 1, 2, and 3 when RCS temperature is greater than or equal to 355 degrees, the number of SI pumps/subsystems is the same in the proposed ITS as the CTS as stated in Description of Change A.2 of this section. LCO 3.5.2 allows both SI flow paths to be isolated for a limited time (2 hours) to perform pressure isolation valve testing. This short period of time provides for only a short additional time (1 hour) before a plant shutdown must be commenced because of two trains of ECCS being inoperable as would be required by LCO 3.0.3 (CTS 15.3.0.B). This limited period allows testing to be performed without having to place the plant unnecessarily into the cold shutdown condition. During the testing the valves are capable of being opened from the control room in a short period of time if the ECCS system is called upon to perform its function. The additional 1 hour of inoperability allowed by this change makes this a less restrictive change. This requirement also supports an orderly transition from hot shutdown to hot stanby (ITS). In Mode 3 with RCS temperature between 355 and 375 degrees, the CTS requires both SI pumps to be operable, therefore, the latitude established in the ITS to heatup to 375 degrees prior to restoring the second SI pump is a relaxation. With the LTOP arming temperature in excess of the Mode 3 boundary temperature, an exception is necessary to allow transition into Mode 3 without reliance upon an Action. When increasing RCS temperature, this exception is necessary as LCO 3.0.4 would preclude entry into Mode 3 due to the LCO Actions not allowing indefinite operation in Mode 1, 2, or 3. When decreasing RCS temperature the provision of Note 2 will allow an SI pump to be rendered inoperable pursuant to LCO 3.4.12, when the RCS temperature in at least one cold leg is less than or equal to 375° F, for a period not to exceed 4 hours. This will allow transition into MODE 4 without requiring entry into the Conditions and Required Actions of LCO 3.5.2. This temperature band (20 degrees, between 355 and 375

DOC Number	DOC Text	
	degrees) was chosen to be controllable without the use of extraordinary measures, providing an allowance to perform an orderly and controlled restoration/disablement of the second SI pump based on LTOP concerns. The 375 degree limit is sufficiently above the LTOP enable temperature to allow for both enabling and disabling injection capability of the SI pump in support of heat up and cooldown operations minimizing the potential for inappropriate actions that could result as a result of a exceedingly tight temperature control band.	
	CTS:	**ITS:**
	15.03.03.A.01	LCO 3.05.02
	15.03.03.A.01.C	LCO 3.05.02
	NEW	LCO 3.05.02 APPL NOTE 1
		LCO 3.05.02 APPL NOTE 2
L.02 Rev. B	CTS 15.4.5.II.A.2 specifies the conditions and manner in which ECCS pump testing must be conducted (run for at least 15 minutes using the full flow test line). This requirement to run the pumps for at least 15 minutes is an arbitrary requirement with no fundamental safety basis. Therefore, these details are being removed. The proposed ITS specifies the safety objective that must be fulfilled by the surveillance tests, while leaving the details associated with testing methods and acceptance verifications to licensee control. These type of details are better suited for procedural control and are not required to be in the ITS to provide adequate protection to the public health and safety. Changes to plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards.	
	CTS:	**ITS:**
	15.04.05.II.A.02	DELETED
L.03 Rev. B	CTS 15.4.5.I.A.1.a specifies the conditions and manner in which ECCS testing must be conducted (RCS pressure less than or equal to 350 psig and RCS temperature less than or equal to 350 degrees, pump breakers may be placed into the "test" position), while CTS 15.4.5.I.A.2 specifies the manner in which equipment operation is to be verified (control board indication and visual indications). These details have been deleted from the Technical Specification, and moved to licensee control as these details are not necessary to describe the actual regulatory requirement (i.e. verification that equipment actuates to its correct position). These details are not required to be in the ITS to provide adequate protection of public health and safety, as the regulatory requirement (verification of equipment actuation) is being maintained in the Technical Specifications. Changes to plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards.	
	CTS:	**ITS:**
	15.04.05.I.A.01	DELETED
	15.04.05.I.A.01.A	DELETED
	15.04.05.I.A.02	DELETED

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text	
L.04 Rev. F	CTS 15.4.5.II.B.2 requires each manual, power operated and automatic valve necessary to ensure system operability in the emergency core cooling system, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position at least once every 31 days. ITS SR 3.5.2.1 requires each manual, power operated and automatic valve in the ECCS flowpath, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position once every 31 days. Requiring verification of the position of the manual, power operated and automatic valves "in the flowpath" results in a relaxation of the current requirement to verify the position of each manual, power operated and automatic valve necessary "to ensure system operability." This change is acceptable, because verifying the correct alignment for the above required valves in the flowpath provides assurance that the proper flowpath will exist for ECCS to meet the acceptance criteria established by 10 CFR 50.46 following a LOCA.	
	CTS:	**ITS:**
	15.04.05.II.B.02	SR 3.05.02.01
LA.01 Rev. A	CTS 15.3.3.A.1.e and CTS 15.3.3.A.1.g list the RHR Heat Exchangers, valves, interlocks, and piping associated with the SI and RHR Systems required to be operable to fulfill the ECCS LCO requirement. These are all attributes associated with system design and configuration, which are adequately captured through application of the definition of operability, and accordingly are still encompassed within the LCOs for ECCS. As such, these details are not required to be in the ITS to provide adequate protection of public health and safety. These attributes are discussed within the Bases for the proposed Point Beach ITS, but have been deleted from the Technical Specifications, changes to these details will be controlled in accordance with the provisions of the Bases Control Program described in Chapter 5 of the Technical Specifications.	
	CTS:	**ITS:**
	15.03.03.A.01.E	DELETED DELETED
LA.02 Rev. B	Not Used.	
	CTS:	**ITS:**
	N/A	N/A
LA.03 Rev. B	Not Used.	
	CTS:	**ITS:**
	N/A	N/A

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
M.01 Rev. A	The CTS contains a provision exempting the requirement to maintain the Safety Injection and Residual Heat Removal Systems operable during low power physics testing. This provision has been deleted in the proposed Technical Specifications. Low power physics testing in the Improved Technical Specifications is a subset of Mode 2. While Mode 2 is typically a non limiting Mode, the operability requirements of the Safety Injection and Residual Heat Removal Systems are independent of physics testing, accordingly this provision has been deleted. This change represent a more restrictive changes as it involves the deletion of a flexibility that currently exists. **CTS:** 15.03.03.A.01 — **ITS:** DELETED
M.02 Rev. A	The CTS states that the ECCS systems and components listed in Specification 15.3.3.A.1.c, f, and g (SI pumps, SI discharge isolation valves, associated valves, interlocks, and piping) are required to be operable prior to the reactor being made critical. However the Actions contained in CTS 15.3.3.A.2 will place the unit in cold shutdown if the SI pump/subsystem is not returned to an operable status within its allowed out of service time, implying an Applicability of Modes 1, 2, 3, and 4 (ITS Modes). CTS 15.3.15.B modifies the requirement of CTS 15.3.3.A.1.c (required number of SI pumps) by stating that one of the two high head Safety Injection pumps are to be rendered inoperable whenever LTOP is required (less than 355 degrees). The ECCS flow paths consist of piping, valves, heat exchangers, and pumps necessary to provide water from the RWST into the RCS during the injection phase and from the containment sump into the RCS during the recirculation phase following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, heat exchangers, and the SI pumps. Each of the two subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. Proposed LCO 3.5.2 requires two trains of ECCS (SI and an RHR subsystem) to be operable in Modes 1, 2, and 3 (greater than or equal to 350 degrees) and allows one of the two SI pumps to be inoperable under specific constraints (up to four hours after entry into Mode 3 or until all RCS cold leg temperatures exceed 375 degrees, whichever comes first). As such, in Modes 1, 2, and 3 when RCS temperature is greater than or equal to 355 degrees, the number of SI pumps/subsystems is the same in the proposed ITS as the CTS as stated in Description of Change A.2 of this section. In Mode 3 with RCS temperature less than 355 degrees, the CTS allows unlimited operation, the ITS, however, becomes more restrictive by imposing a four hour time constraint for restoring the second SI pump to operable status after entry into Mode 3. This limitation is a more restrictive change imposed to assure timely restoration of the second SI pump, consistent with the objective of maintaining single failure protection in Modes 1, 2, and 3 for this system. The 375 degree SI pump restoration/disablement constraint is discussed in Description of Changes L.1 of this section. The Mode 4 ECCS aspects of this LCO are discussed in LCO section 3.5.3. **CTS:** 15.03.03.A.01.C — **ITS:** LCO 3.05.02 **CTS:** 15.03.15.B.01 — **ITS:** LCO 3.05.02 APPL NOTE 2

DOC Number	DOC Text	
M.03 Rev. A	CTS 15.3.3.A.2, CTS 15.3.3.A.2.b, and CTS 15.3.3.A.2.c requires a unit to be placed into hot shutdown within 6 hours and cold shutdown within 36 hours if a single SI pump (other pump is operable) or valve affecting a single SI subsystem (duplicative function still operable) is not restored to operable status in 72 hours. ITS LCO 3.5.2 Condition A allows 72 hours for an SI subsystem to be inoperable, prior to requiring the unit to be placed into Mode 3 within 6 hours and Mode 4 within 12 hours. Accordingly, the CTS does not specify a specific time limit for placing the unit into Mode 4. The addition of this time limit is a more restrictive change, necessary to establish a bounding limit to exit the Mode of Applicability when an SI subsystem is inoperable. The CTS action to place the unit in cold shutdown is covered in the Description of Changes associated with LCO 3.5.3.	
	CTS:	**ITS:**
	NEW	LCO 3.05.02 COND B RA B.2
M.04 Rev. A	The Actions contained in 15.3.3.A.3 for a single inoperable RHR subsystem will place the unit in hot shutdown within 6 hours if the RHR System is not returned to an operable status within its allowed out of service time. CTS 15.3.3.A.3 will then require the unit to be maintained greater than 350 degrees (ITS Mode 3). Proposed LCO 3.5.2 Action B will require the unit to be placed into Mode 3 within 6 hours and Mode 4 within 12 hours. The requirement to place the unit in mode 4 within 12 hours is a more restrictive requirement, as the CTS would allow indefinite operation greater than 350 degrees. This requirement places the unit in a Mode of Applicability for which redundant RHR ECCS subsystems are not required. Maintaining redundancy in heat removal is not addressed within this LCO as the Mode of Applicability for this LCO is above the cut in temperature limit for the RHR system. The heat removal aspects are discussed in Section 3.4.	
	CTS:	**ITS:**
	NEW	LCO 3.05.02 COND B RA B.2
M.05 Rev. A	CTS 15.4.5.I.A.1 and 15.4.5.I.A.2 require Safety Injection System tests to be performed during reactor shutdowns for major fuel loadings. These tests are intended to ensure that all components receive their Safety Injection (SI) signal, appropriate pump motor breakers open and close as well as verifying that all valves actuate and travel to their correct position. The proposed ITS for Point Beach (SR 3.5.2.3 and 4) will require each ECCS pump and each automatic valve in the flowpath that is not locked, sealed, or otherwise secured in position, either start or actuates to its correct position, as applicable, on an actual or simulated actuation signal at least once every 18 months. The CTS and the ITS impose the same testing, but the CTS does not define a specific frequency of performance for these Surveillance, but rather an evolution, which can vary significantly from outage to outage with no bounding limit. Accordingly, the adoption of a bounding frequency (18 months) is a more restrictive change.	
	CTS:	**ITS:**
	15.04.05.I.A.01	SR 3.05.02.03 SR 3.05.02.04

DOC Number	DOC Text	
M.06 Rev. A	CTS 15.4.b.II.B.1 requires a visual inspection of each containment sump suction inlet and strainer to verify that there is no restriction or evidence of structural distress or abnormal corrosion at least each refueling outage. The proposed ITS for Point Beach both require a visual inspection of each ECCS train containment sump suction inlet for restriction by debris and inspection of the debris screen for structural distress and abnormal corrosion at least once per 18 months. The CTS requirement is the same as the proposed ITS with the exception of the specified frequency. The CTS does not define a specific frequency of performance for these Surveillance, but rather an evolution, which can vary significantly from outage to outage with no bounding limit. Accordingly, the adoption of a bounding frequency (18 months) is a more restrictive change.	
	CTS:	**ITS:**
	15.04.05.II.B.01	SR 3.05.02.05
M.07 Rev. A	CTS 15.3.3.A.2 and 15.3.3.A.3 provide separate Conditions and Required Actions for inoperable residual heat removal and safety injection system components. In having separate conditions, simultaneous inoperability of a safety injection and residual heat removal subsystem is allowed. The Point Beach ECCS piping design is capable of supporting cross-train operation of the residual heat removal and safety injection subsystems. However, cross-train operation in the post accident recirculation mode of operation requires local valve manipulations which is not currently addressed by the emergency operating procedures. As such, ITS LCO 3.5.2 only provides Required Actions for a single Train of ECCS being inoperable, thereby limiting the simultaneous inoperability of the safety injection and residual heat removal subsystems to the same ECCS Train.	
	CTS:	**ITS:**
	15.03.03.A.02	LCO 3.05.02 COND A
	15.03.03.A.03	LCO 3.05.02 COND A

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
R.01 Rev. A	Wisconsin Electric Power Company has utilized the selection criteria provided in the 10 CFR 50.36.ii, and has concluded that the Boric Acid System can be relocated to licensee control. The basis for this conclusion is as follows: The boric acid system ensures negative reactivity control is available for normal operation (normal makeup and chemical shim reactivity control) and provides an alternate method for borating the reactor coolant system. However, this system is not assumed to mitigate any design basis accident or transient. Other systems (e.g., SI pumps) and other borated water sources (RWST) are assumed in the safety analysis. Comparison to Screening Criteria: 1. The boric acid system is not used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary prior to a design basis accident (DBA). 2. The boric acid system is not used to indicate status of, or monitor a process variable, design feature, or operating restriction that is an initial condition of a DBA or transient. 3. The boric acid system is not part of a primary success path in the mitigation of a DBA or transient. 4. As discussed in Section 4.0 (Appendix A, pages A-8 and A-10) and summarized in Table 1 of WCAP-11618, the loss of the boric acid system was found to be a non-significant risk contributor to core damage frequency and offsite releases. Wisconsin Electric Power Company has reviewed this evaluation and considers it applicable to Point Beach Station. The Point Beach IPE confirms this judgment for Point Beach Station. Boration, when needed, can be accomplished with the RWST, as well as the boric acid system.

CTS:	ITS:
15.03.02 T 15.03.02-01	TRM 3.05.01
15.03.02.A	TRM 3.05.01 TRM 3.05.01
15.03.02.B	TRM 3.05.01 TRM 3.05.01
15.03.02.B.01	TRM 3.05.01 TRM 3.05.01
15.03.02.B.02	TRM 3.05.01 TRM 3.05.01
15.03.02.B.03	TRM 3.05.01 TRM 3.05.01
15.03.02.B.03.A	TRM 3.05.01 TRM 3.05.01
15.03.02.B.03.B	TRM 3.05.01

Description of Changes - NUREG-1431 Section 3.05.02

09-May-01

DOC Number	DOC Text
15.03.02.B.03.B	TRM 3.05.01
15.03.02.C	TRM 3.05.01
	TRM 3.05.01
15.03.02.C.01	TRM 3.05.01
	TRM 3.05.01
15.03.02.C.02	TRM 3.05.01
	TRM 3.05.01
15.03.02.C.03	TRM 3.05.01
	TRM 3.05.01
15.03.02.C.03.A	TRM 3.05.01
	TRM 3.05.01
15.03.02.C.03.B	TRM 3.05.01
	TRM 3.05.01
15.03.02.D	TRM 3.05.01
	TRM 3.05.01
15.03.02.D.01	TRM 3.05.01
	TRM 3.05.01
15.03.02.D.02	TRM 3.05.01
	TRM 3.05.01
15.03.02.D.03	TRM 3.05.01
	TRM 3.05.01
15.04.01 T 15.04.01-01 21	TRM 3.03.01 T 3.03.01-01 04
15.04.01 T 15.04.01-01 22	TRM 3.03.01 T 3.03.01-01 05
15.04.01 T 15.04.01-01 23	TRM 3.03.01 T 3.03.01-01 06
15.04.01 T 15.04.01-02 04	TRM 3.05.01
15.04.01 T 15.04.01-02 20	TRM 3.05.01
15.04.01 T 15.04.01-02 20 (19)	TRM 3.05.01
15.04.01 T 15.04.01-02 31	TRM 3.05.01
15.04.01 T 15.04.01-02 31 (17)	TRM 3.05.01
BASES	TRM 3.05.01

A.1

A.9

SR 3.5.2.2

< See Section 3.6 >

containment spray pumps shall be tested in accordance with the Inservice Test Program.

2. Acceptable levels of performance shall be that the pumps start, reach their required developed head at, and operate ~~for~~ at least ~~fifteen minutes~~ on the full-flow ~~test~~ lines. L.2

B Errata #50

B. Other

18 months M.6

SR 3.5.2.5

1. At least ~~every refueling~~, verify by visual inspection each containment sump suction inlet is not restricted by debris and the debris strainers show no evidence of structural distress or abnormal corrosion.

L.4

SR 3.5.2.1

F Errata #165

2. Verify each manual, power operated, and automatic valve necessary to insure system operability in the emergency core cooling and containment spray systems that is not locked, sealed, or otherwise secured in position, is in the correct position at least once every 31 days.

< See Section 3.6 >

Basis

A.8

The Safety Injection System and the Containment Spray System are principal plant Safety Systems that are normally inoperative during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is therefore to combine systems tests to be performed during refueling shutdowns, with more frequent component tests, which can be performed during reactor operation.

Justification For Deviations - NUREG-1431 Section 3.05.02

09-May-01

JFD Number	JFD Text	
01 Rev. A	The proposed Bases have been modified to reflect the Point Beach design basis accidents assumptions. Use of WCAP 10924-P, Revision 1, "Westinghouse Large-Break LOCA Best-Estimate Methodology" was approved for use at Point Beach as part of Amendments 120 and 123 to the Point Beach Technical Specifications issued May 8, 1989. WCAP 10924 established that the most limiting peak clad temperature as a result of a large break LOCA occurs with offsite power available. Maintaining offsite power results in the most limiting peak clad temperatures for the following reasons. In maintaining offsite power, the worst case single failure becomes the loss of the largest ECCS pump, the residual heat removal (RHR) pump. Loss of a RHR pump alone results in a lower containment pressure due to the availability of both containment spray systems and all four containment fan cooler units. By maintaining full containment cooling capability, containment pressure is minimized which increases the rate of RCS blowdown, while the loss of the largest ECCS pump decreases the amount of SI flow available to reflood the core. Continued operation of the reactor coolant pumps during the blowdown phase of a large break LOCA increases the rate of RCS blowdown while lowering the mass flow rate through the core. During the reflood phase, the reactor coolant pumps are assumed to cease operation, obtaining a locked rotor flow resistance to delay core reflood. All of these assumptions result in an increase in core reflood time leading to higher peak clad temperatures. The small break LOCA is analyzed for Point Beach using the methods contained in WCAP 10054-P-A "Westinghouse Small Break ECCS Evaluation Model Using The NOTRUMP code. The design basis small break LOCA analysis assumes loss of offsite power with the limiting single failure conservatively taken to be loss of one train of ECCS.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
		B 3.05.02
02 Rev. A	The brackets have been removed and the proper plant specific information has been provided.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
	LCO 3.05.02	LCO 3.05.02
	SR 3.05.02.03	SR 3.05.02.05
	SR 3.05.02.04	SR 3.05.02.06
	SR 3.05.02.05	SR 3.05.02.08

Justification For Deviations - NUREG-1431 Section 3.05.02

09-May-01

JFD Number	JFD Text
03 Rev. A	NUREG 1431 contains a 31 day surveillance requirement which verifies that the ECCS piping is full of water. This surveillance is not contained in the CTS, and was not adopted, based on this surveillance being an unnecessary burden. The purpose of this SR is to ensure that the ECCS system piping is filled and vented. The ECCS piping at Point Beach is routed in such a manner as to preclude the need for periodic venting. All ECCS subsystem piping runs are routed below normal RWST level, thereby maintaining positive system pressure at all times. This pressure precludes inleakage through any source open to the atmosphere. The Bases section associated with this SR has similarly been omitted, and all subsequent SR numbers have been changed in both the LCO and Bases.

ITS:	NUREG:
N/A	B 3.05.02 SR 3.05.02.03 SR 3.05.02.07
SR 3.05.02.02	SR 3.05.02.04
SR 3.05.02.03	SR 3.05.02.05
SR 3.05.02.04	SR 3.05.02.05 SR 3.05.02.06
SR 3.05.02.05	SR 3.05.02.08

JFD Number	JFD Text
04 Rev. A	NUREG 1431 requires an 18 month inspection of the "trash racks and screens". The CTS and plant nomenclature describes this plant feature as the "debris screens". In addition, the CTS refers to the accumulators as SI accumulators, not ECCS accumulators. Accordingly, the proposed ITS for Point Beach have been written to retain the site specific nomenclature for these features.

ITS:	NUREG:
SR 3.05.02.05	SR 3.05.02.08

Justification For Deviations - NUREG-1431 Section 3.05.02

09-May-01

JFD Number	JFD Text	
05 Rev. A	The Bases for NUREG 1431 has been modified to reflect Point Beach's design. Point Beach is a low head Safety Injection plant, which does not credit the operation of the Charging Pumps relative to an ECCS function. Only the Safety Injection and Residual Heat Removal Pumps are ECCS subsystems. The ECCS systems at Point Beach do not include hot leg recirculation as a phase of ECCS operation. The Point Beach design incorporates only an injection phase and a recirculation phase. The RHR subsystem normally supplies injection to the RCS via the upper plenum injection nozzles. Normally closed valves in the upper plenum injection lines open upon receipt of a Safety Injection signal. The SI subsystem supplies injection via the RCS cold legs. All reference to hot leg recirculation have been deleted, the injection discussions have been altered to reflect the two modes of operation and the RHR/SI injection points, and the upper plenum injection line automatic valves have been addressed. These changes are required to accurately reflect the Point Beach design.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
06 Rev. A	The Point Beach design does not include a Boric Acid Injection Tank. Accordingly, this LCO and reference to the function of a BIT in other Bases Sections were not incorporated as part of the Point Beach conversion to the ITS.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
07 Rev. A	The current licensing basis for Point Beach does not include feedwater line break scenarios. Accordingly, reference to Feedwater line break events in the Bases of the proposed ITS have been deleted.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
08 Rev. A	The Bases for NUREG 1431 states that the ECCS and Containment Spray pumps take suction from separate redundant supply lines. The Point Beach ECCS and Containment Spray pumps are supplied from a common header. As such, the Bases has been modified to delete reference to separate and redundant supply lines, reflective of Point Beach's design.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
09 Rev. A	The Bases discussion relative to small break LOCA has been altered to reflect the accident analysis for Point Beach. For small break LOCAs which are too small to depressurize the RCS below the shutoff head of the safety injection pumps, the steam generators provide core cooling until RCS decreases below the shutoff pressure for the safety injection pumps.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02

Justification For Deviations - NUREG-1431 Section 3.05.02

09-May-01

JFD Number	JFD Text
10 Rev. A	The Bases for NUREG LCO 3.5.2 discusses the maximum number of "ECCS" pumps that are permissible during low temperature operating conditions based on overpressure concerns. ECCS pumps has been changed to "pumps". For most plants, the only pumps that influence the overpressure analysis are the ECCS pumps. Point Beachs' low temperature overpressure analysis requires that a number of non-ESF pumps are also incapable of injecting (e.g. charging pumps). As such, the Bases has been modified to reflect Point Beach's licensing basis. **ITS:** B 3.05.02 **NUREG:** B 3.05.02
11 Rev. A	Reference to the General Design Criteria (GDC) of 10 CFR 50 Appendix A has been deleted from the Bases of the Technical Specifications, substituting reference to the appropriate section of the FSAR which specifies the Point Beach design criteria. Point Beach was constructed and licensed prior to the GDC being issued. The Point Beach construction permit was issued prior to the GDCs being issued in 1971. Point Beach was designed and constructed utilizing the 1967 proposed GDCs. Accordingly, reference has been provided to the appropriate criteria and section of the Point Beach FSAR which provides explanation of Point Beach's design basis. **ITS:** B 3.05.02 **NUREG:** B 3.05.02
12 Rev. A	NUREG 1431 contains reference to two sections of the FSAR for containment mass and energy calculation. Only section 14 of the Point Beach FSAR contains this information, accordingly only one reference is necessary in the Bases. **ITS:** B 3.05.02 **NUREG:** B 3.05.02
13 Rev. A	The ECCS subsystems for Point Beach are normally aligned to the RWST. In addition, suction transfer from the RWST to the containment sump is manually performed. As such, the Bases statements in NUREG 1431 related to the capability of the ECCS subsystems to take suction form the RWST and automatically transferring suction to the containment sump have been modified to reflect Point Beach's design. **ITS:** B 3.05.02 **NUREG:** B 3.05.02
14 Rev. A	The Bases of the ITS have been written to reflect the plant design and operability requirements specified in LCO 3.3.2. The Bases for ECCS states below Mode 3 the SI signal setpoint is manually bypassed by operator control, while the system design for Point Beach bypasses the low pressurizer pressure and low steam generator pressure signal, leaving the containment high pressure signal in the actuation loop. **ITS:** B 3.05.02 **NUREG:** B 3.05.02

JFD Number	JFD Text	
15 Rev. F	Not used.	
	ITS:	**NUREG:**
	N/A	N/A
16 Rev. A	LCO 3.9.2 "Unborated Water Source Isolation Valves" was not adopted based on the Point Beach design. Accordingly, the references to LCO 3.9.5 and 6 have been revised to reflect the renumbering that has occurred in the 3.9 Section of the ITS.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
17 Rev. A	The Bases for SR 3.5.2.8 states that one of the reasons for an 18 month containment sump suction inspection is the potential for unplanned transient if the surveillance were performed with the reactor at power. This surveillance consists of a visual inspection which would not present the potential for an unplanned transient. Plant conditions required to access the area have been retained in the Bases as the actual rational.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
18 Rev. F	Not used.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
19 Rev. A	The purpose of NUREG 1431 SR 3.5.2.1 is to verify alignment and deenergization of power operated valves in the ECCS system which could render both trains of ECCS inoperable if the valve became misaligned due to a single active failure. The CTS for Point Beach does not contain this requirement and there are no power operated valves in the ECCS system which could render both trains of ECCS inoperable due to a single active failure. Accordingly, this requirement has not been adopted. The Bases section associated with this SR and reference to inoperabilities stemming from single valve mispositionings have similarly been omitted, and all subsequent SR numbers have been changed in both the LCO and Bases. Reference 6 has been deleted, as this reference will no longer be used.	
	ITS:	**NUREG:**
	B 3.05.02	B 3.05.02
	N/A	SR 3.05.02.01
	SR 3.05.02.01	SR 3.05.02.02

JFD Number	JFD Text
20 Rev. A	The purpose of NUREG 1431 SR 3.5.2.7 is to verify proper ECCS throttle valve positioning which restricts injection flow to a ruptured cold leg, ensuring that the other cold leg receives at least the minimum assumed ECCS flow. Point Beach does not have ECCS throttle valves which are used for this purpose, and the CTS does not contain any requirement to verify ECCS throttle valve positions. Accordingly, this requirement has not been adopted. The Bases discussion about this design feature and SR have similarly been omitted, and all subsequent SR numbers have been changed in both the LCO and Bases. **ITS:** B 3.05.02; N/A; SR 3.05.02.05 **NUREG:** B 3.05.02; SR 3.05.02.07; SR 3.05.02.08
21 Rev. A	The Bases of LCO 3.5.2 discusses an ECCS design which is sequenced upon receipt of any SI signal. Point Beach's ECCS subsystems are block loaded upon receipt of an SI signal if offsite power is available, and will be sequenced in a predetermined order and time if offsite power is not available. Accordingly, the Bases has been changed to clarify Point Beach's design. **ITS:** B 3.05.02 **NUREG:** B 3.05.02
22 Rev. A	NUREG 1431 LCO 3.5.2 allows multiple ECCS trains to be inoperable, providing 100% of the ECCS flow equivalent to a single ECCS train is available. Multiple inoperable pumps in redundant trains is acceptable based on interconnections between redundant ECCS Trains, providing the capability to utilize components from the opposite ECCS train in establishing the required ECCS flow paths during the injection and recirculation phases of an accident. The Point Beach ECCS piping design is capable of supporting cross-train operation of the residual heat removal and safety injection subsystems; however, cross-train operation in the post accident recirculation mode of operation would require local valve manipulations which is not currently addressed by the emergency operating procedures. Proposed ITS LCO 3.5.2 has been rewritten defining ECCS train operability to consist of an RHR pump system, an SI pump system, and the capability to support recirculation phase operation. This will allow only a single train of ECCS to be inoperable, thereby limiting the simultaneous inoperability of the safety injection and residual heat removal subsystems to the same ECCS Train in order to preserve ECCS recirculation phase capability. Changes have also been made where necessary in the Bases to address this issue. This change is necessary based on Point Beach's design and operation. TSTF 325, Revision 0 therefore, also was not incorporated. **ITS:** B 3.05.02; LCO 3.05.02 COND A **NUREG:** B 3.05.02; LCO 3.05.02 COND A; LCO 3.05.02 COND A

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS – Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

Moved Note to LCO IAW Approved Traveler TSTF 153

APPLICABILITY: MODES 1, 2, and 3.

2

-------------------------NOTES-------------------------

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1

2. ~~Operation in MODE 3 with ECCS pumps declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds [375]°F, whichever comes first.~~

2

F Errata #31

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
22 A. One ~~or more~~ ECCS train~~s~~ inoperable. ~~AND~~ ~~At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.~~	A.1 Restore train~~(s)~~ to OPERABLE status.	72 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

BASES

LCO (continued)

5

to take its supply from the containment sump ~~and to supply its flow to the RCS hot and cold legs.~~

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

Applicability Note 1 moved to here IAW Approved TSTF 153

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. ~~The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power.~~ The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

5

14

low pressurizer pressure and low steam generator pressure automatic SI signals are

This LCO is only applicable in MODE 3 and above. Below MODE 3, the ~~SI signal setpoint is~~ manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS—Shutdown."

SI pump

the Note

Approved TSTF 153

2

As indicated in ~~Note 1~~, the flow path s may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room.

~~As indicated in Note 2, operation in MODE 3 with ECCS trains declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that certain pumps be rendered inoperable at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.~~

F
Errata #31

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is

Move to LCO Section IAW Approved TSTF 153

LCO 3.5.2 BASES INSERTS

INSERT B 3.5.2-1:

The residual heat removal (RHR) pumps provide RCS injection directly into the upper reactor vessel plenum via the core deluge injection lines, while the safety injection (SI) pumps provide RCS injection via the cold legs.

INSERT B 3.5.2-2:

(Not used)

F Errata #31

INSERT B 3.5.2-3:

ECCS Train interconnections could allow utilization of components from the opposite ECCS train to achieve the required ECCS flowpaths, however, cross train operation in the recirculation mode of operation requires local valve manipulations. Based on estimated times to establish the required valve line ups, the capability of establishing ECCS recirculation mode without interrupting injection flow to the core could be impaired. Therefore, with more than one component inoperable such that both Trains of ECCS are inoperable, the facility is in a condition outside of its design basis.

INSERT B 3.5.2-4:

Neither does the inoperability of multiple components in the same train (e.g. the "A" SI pump and the "A" RHR pump), result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that a single OPERABLE ECCS train remains available.

INSERT B 3.5.2-5:

With more than one component inoperable such that both ECCS trains are not available, the facility is in a condition outside design and licensing basis. Therefore, LCO 3.0.3 must be immediately entered.

No Significant Hazards Considerations - NUREG-1431 Section 3.05.02

09-May-01

NSHC Number	NSHC Text
A Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change involves reformatting and rewording of the current Technical Specifications. The reformatting and rewording process involves no technical changes to existing requirements. As such, this change is administrative in nature and does not impact initiators of analyzed events or assumed mitigation of accident or transient events. Therefore, this change does not increase 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will not impose any new or eliminate any old requirements. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The proposed change will not significantly reduce the margin of safety because it has no impact on any safety analysis assumptions. This change is administrative. As such, there is no technical change to the requirements and, therefore, there is no reduction in the margin of safety.

NSHC Number	NSHC Text
L.01 Rev. A	1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The addition of a short period of time to allow both SI pump flow paths to be isolated provides for a short period of time to perform pressure isolation valve testing when the system is otherwise required to be operable. During this time, the isolation valves are under direct control from the control room such that system function can be restored expeditiously if called upon. This short period of inoperability cannot increase the probability of an accident and since system function can be restored directly by the control room the consequences of an accident previously evaluated will not be significantly increased. The addition of a temperature limitation to the ECCS LCO for Low Temperature Overpressure Protection (LTOP) will allow the flexibility necessary to enable and disable Safety Injection (SI) pumps prior to entry into and exiting the LTOP Mode of Applicability during Mode 3. This change does not result in any hardware changes. SI pumps status/availability is assumed relative to the initial conditions and function in the mitigation of analyzed events, but is not assumed to be an initiator of any analyzed event. The change will allow operation for a limited period of time (four hours) within a small temperature band (355 to 375 degrees) to restore or disable the second SI pump for Low Temperature Overpressure concerns. Core energy levels are not significantly increased through the added 20 degree allowance (355 to 375 degrees). Therefore, the consequences of an event will not be significantly affected. Therefore, the proposed change does not increase 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? The proposed change does not result in any physical alterations to the plant (no new or different type of equipment will be installed). The short period of time (2 hours) for SI flow path inoperability ensures system is restored expeditiously. During the time of inoperability, operators can directly restore the flow path from the control room if called upon. The additional 20 degree temperature band in which the second SI pump may be inoperable is a flexibility required for the enable and disable a second SI pump for LTOP concerns which does not introduce any new or significant challenges to plant operation. This provision allows an appropriate bound for either restoration or disablement of a second pump during a plant heatup and cooldown operations, which is necessary for LTOP concerns. The proposed change will limit unit operation above 350 degrees to a maximum of four hours. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? During the short period of time two SI flow paths can be isolated, the flow paths are under operator control and can be unisolated from the control room expeditiously if called upon. This ensures the SI system can perform its function as designed. Therefore, a significant reduction in a margin of safety cannot result.

NSHC Number	NSHC Text
	The additional 20 degree temperature band in which the second SI pump may be inoperable is a flexibility required for the enable and disable a second SI pump for LTOP concerns. This limitation allows an appropriate bound for restoration or disablement of a second pump during a plant heatup or cooldown, and is acceptable based upon the reduced thermal energy in the core and sufficient time for manual actuation of the remaining ECCS pumps if necessary. The proposed change will limit unit operation above 350 degrees in this configuration to four hours. Accordingly, this change will have an insignificant effect on margin of safety.
L.02 Rev. B	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. The proposed change results in the deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? The deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety, does not result in a significant reduction in the margin of safety.

NSHC Number	NSHC Text
L.03 Rev. B	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. The proposed change results in the deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? The deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety, does not result in a significant reduction in the margin of safety.

NSHC Number	NSHC Text
L.04 Rev. F	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change results in a relaxation of requirements such that only the ECCS manual, power operated and automatic valves in the flowpath that are not locked, sealed, or otherwise secured in position are verified to be in the correct alignment. The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? This change does not involve a significant reduction in a margin of safety because the ability of ECCS to perform its safety functions is still verified. The intent of the surveillance requirement has not been altered and does not result in a reduction in the margin of safety.

NSHC Number	NSHC Text
LA Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change relocates requirements from the Technical Specifications to the Bases, FSAR, or other plant controlled documents. The Bases and FSAR will be maintained using the provisions of 10 CFR 50.59. In addition to 10 CFR 50.59 provisions, the Technical Specifications Bases are subject to the change process in the Administrative Controls Chapter of the ITS. Plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards. Changes to the Bases, FSAR, or other plant controlled documents will be evaluated in accordance with the requirements of the Bases Control Program in Chapter 5.0 of the ITS, 10 CFR 50.59, or plant administrative processes. Therefore, no increase in the probability or consequences of an accident previously evaluated will be allowed. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will not impose any different requirements and adequate control of the information will be maintained. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The proposed change will not reduce a margin of safety because it has no impact on any safety analysis assumptions. In addition, the requirements to be moved from the Technical Specifications to the Bases, FSAR, or other plant controlled documents are as they currently exist. Future changes to the requirements in the Bases, FSAR, or other plant controlled documents will be evaluated in accordance with the requirements of 10 CFR 50.59, the Bases Control Program in Chapter 5.0 of the ITS, or the applicable plant process and no reduction in a margin of safety will be allowed.

NSHC Number	NSHC Text
M Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change provides more restrictive requirements for operation of the facility. These more stringent requirements do not result in operation that will increase the probability of initiating an analyzed event and do not alter the assumptions relative to the mitigation of an accident or transient event. These more restrictive requirements continue to ensure process variables, structures, systems and components are maintained consistent with the safety analyses. Therefore, this change does not increase 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change does impose different requirements. However, these changes are consistent with assumptions made in the safety analysis. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The imposition of more restrictive requirements either has no affect on or increases the margin of safety. Each change is providing additional restrictions to enhance plant safety. These changes are consistent with the safety analysis. Therefore, this change does not involve a reduction in a margin of safety.

NSHC Number	NSHC Text
R Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change relocates requirements and surveillances for structures, systems, components or variables which did not meet the criteria for inclusion in Technical Specifications as identified in the 10CFR 50.36 Technical Specification Selection Criteria. The affected structures, systems, components or variables are not assumed to be initiators of analyzed events and are not assumed to mitigate accident or transient events. The requirements and surveillances for these affected structures, systems, components or variables will be relocated from the Technical Specifications to an appropriate administratively controlled document and maintained pursuant to 10CFR 50.59. Therefore, this change does not increase 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or change in parameters governing normal plant operation. The proposed change will not impose any different requirements and adequate control of information will be maintained. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The proposed change will not reduce a margin of safety because it has no impact on any safety analysis assumptions. In addition, the affected requirement will be relocated to an owner controlled document for which future changes will be evaluated pursuant to the requirements of 10CFR 50.59. Therefore, this change does not involve a reduction in a margin of safety.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS—Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

-----------------------------------NOTE-------------------------------------
In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

F Errata #31

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ECCS train inoperable.	A.1 Restore train to OPERABLE status.	72 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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.2.2	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.5.2.4	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.5.2.5	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet debris screens show no evidence of structural distress or abnormal corrosion.	18 months

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are two phases of ECCS operation: injection and recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS). The residual heat removal (RHR) pumps provide RCS injection directly into the upper reactor vessel plenum via the core deluge injection lines, while the safety injection (SI) pumps provide RCS injection via the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for recirculation.

The ECCS consists of two separate subsystems: safety injection (SI) (high head), and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The SI accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps necessary to provide water from the RWST into the RCS during the injection phase and from the containment sump into the RCS during the recirculation phase following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, heat exchangers, and the SI pumps. Each of the two subsystems consists

BASES

BACKGROUND (continued)

of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. ECCS Train interconnections could allow utilization of components from the opposite ECCS train to achieve the required ECCS flowpaths; however, cross train operation in the recirculation mode of operation requires local valve manipulations. Based on estimated times to establish the required valve line ups, the capability of establishing ECCS recirculation mode without interrupting injection flow to the core could be impaired. Therefore, with more than one component inoperable such that both Trains of ECCS are inoperable, the facility is in a condition outside of its design basis.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the steam generators provide core cooling until the RCS pressure decreases below the SI pump shutoff head.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps then supply the SI pumps.

The SI subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The ECCS subsystems are actuated upon receipt of an SI signal. If offsite power is available, the safeguard loads start immediately. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, upper plenum injection line valve stroke, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

BASES

BACKGROUND (continued)

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet the Point Beach Design Criteria (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps. The SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the SI pumps, as well as the maximum response time for their actuation. The SGTR and MSLB events also credit the SI pumps. The small break LOCA and MSLB events establish the maximum response time for the SI pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with offsite power available and a single failure disabling one RHR pump (offsite power is assumed for modeling full containment heat removal and reactor coolant pump operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water injected into the reactor vessel upper plenum and RCS cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Ref. 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA.

It also ensures that the SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality.

For smaller LOCAs, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of the NRC Policy Statement.

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of, an SI subsystem, and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path taking suction from the RWST upon an SI signal and capable of manually transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to the RCS. In the long term, this flow path may be switched to take its supply from the containment sump.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

As indicated in the Note, the SI pump flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily

F
Errata #31

BASES

LCO (continued)

restorable from the control room.

F
Errata #31

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the low pressurizer pressure and low steam generator pressure automatic SI signals are manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS — Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. 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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

ACTIONS

A.1

With one train inoperable, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering the limiting design basis analysis flow rate to the RCS or if the train is not capable of supporting recirculation mode operation. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of multiple components in the same train (e.g. the "A" SI pump and the "A" RHR pump), result in a loss of function for the ECCS.

The intent of this Condition is to maintain a combination of equipment

ACTIONS (continued)

such that a single OPERABLE ECCS train remains available.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

With more than one component inoperable such that both ECCS trains are not available, the facility is in a condition outside design and licensing basis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist 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 3.5.2.2

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance

BASES

SURVEILLANCE REQUIREMENTS (continued)

of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.3 and SR 3.5.2.4

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.5

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and on the need to have access to the location. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. FSAR, Section 6.1.1.
2. 10 CFR 50.46.
3. FSAR, Section 6.2.1.
4. FSAR, Chapter 14, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

Description of Changes - NUREG-1431 Section 3.05.03

09-May-01

DOC Number	DOC Text
A.01 Rev. A	In the conversion of Point Beach current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the Standard Technical Specifications, Westinghouse Plants, NUREG-1431, Revision 1 (i.e., Improved Standard Technical Specifications (ISTS)).

CTS:	ITS:
15.03.03 APPL	LCO 3.05.03
15.04.05.II.A.01	SR 3.05.03.01 - SR 3.05.02.02
15.04.05.II.A.02	SR 3.05.03.01 - SR 3.05.02.02

A.02
Rev. A

The CTS states that the ECCS systems and components listed in Specification 15.3.3.A.1.c, d, e, f, and g (SI pumps, RHR pumps and heat exchangers, SI discharge isolation valves, associated valves, interlocks, and piping) are required to be operable prior to the reactor being made critical.

However the Actions contained in CTS 15.3.3.A.2 for the SI pump/subsystem will place the unit in cold shutdown if the pump/subsystem is not returned to an operable status within its allowed out of service time, implying an Applicability of Modes 1, 2, 3, and 4 (ITS Modes). CTS 15.3.15.B modifies the requirement of CTS 15.3.3.A.1.c (required number of SI pumps) by stating that one of the two high head Safety Injection pumps are to be rendered inoperable whenever LTOP is required (less than 355 degrees). Accordingly, the CTS requires only one SI pump/subsystem to be operable in Mode 4 (200 - 350 degrees).

Similarly, the Actions contained in CTS 15.3.3.A.3 for a single inoperable RHR subsystem allow the unit to be maintained greater than 350 degrees (ITS Mode 3) indefinitely, as long as the RHR subsystem is not being relied upon for redundancy in decay heat removal. The CTS does not contain any Actions for the RHR subsystem below 350 degrees unless it is being relied upon for redundancy in decay heat removal. Accordingly, the CTS allows indefinite operation in the equivalent to ITS Mode 4 with only a single RHR pump/subsystem operable.

ITS LCO 3.5.3 requires a single train of ECCS (one SI and one RHR subsystem) to be operable in Mode 4 as the CTS does, making the Applicability for a single pump system an administrative change. However, the CTS does not require the SI and RHR subsystems to be associated with the same ECCS train. Requiring both ECCS pump systems to be associated with the same train is addressed in Description of Change M.4 of this LCO.

CTS:	ITS:
15.03.03.A.01	LCO 3.05.03
15.03.15.B.01	LCO 3.05.03

Description of Changes - NUREG-1431 Section 3.05.03

09-May-01

DOC Number	DOC Text	
A.03 Rev. A	The Bases of the current Technical Specifications for this LCO have been completely replaced by the revised Bases reflecting the format and applicable content of the Improved Technical Specifications for Point Beach. The proposed Bases are based on NUREG 1431 Rev. 1. The proposed Bases for this LCO are consistent and supportive of the proposed LCO, and accordingly is administrative.	
	CTS:	**ITS:**
	BASES	B 3.05.03
A.04 Rev. A	CTS 15.4.2.B.3 and CTS 15.4.5.II.A.1 require the SI and RHR pumps to be tested in accordance with ASME Section XI. ITS SR 3.5.3.1 references the performance of SR 3.5.2.2 which requires each ECCS pump to be tested in accordance with the Inservice Testing Program. Accordingly, while presented in a different fashion than the CTS, the ITS will continue to require ASME pump testing.	
	CTS:	**ITS:**
	15.04.02.B.03	SR 3.05.03.01 - SR 3.05.02.02
	15.04.05.II.A.01	SR 3.05.03.01 - SR 3.05.02.02
A.05 Rev. A	NUREG 1431 contains a note as part of SR 3.5.3.1 which allows an RHR train to be considered operable during alignment and operation for decay heat removal, providing the train is capable of being manually realigned to the ECCS mode of operation. This note has been moved to the LCO Section of the proposed ITS in accordance with TSTF 90 which has been approved for incorporation into Revision 2 of NUREG 1431. The CTS, while not explicitly stated in the same fashion, recognizes this allowance through the application of LCO 15.3.3.A.3, which provide LCO Requirements and Actions for redundant heat removal trains in Mode 4. Accordingly, while presented differently, this latitude exists in the CTS making this change administrative.	
	CTS:	**ITS:**
	NEW	LCO 3.05.03 NOTE
A.06 Rev. A	The CTS provides an introductory statement (Applicability) which simply states which systems/components are addressed within a given section. This same information while worded differently is contained within the title of each ITS LCO. Accordingly, this change is a change in format with no change in technical requirement.	
	CTS:	**ITS:**
	15.03.03 APPL	LCO 3.05.03
	15.04.05 APPL	LCO 3.05.03

Description of Changes - NUREG-1431 Section 3.05.03

09-May-01

DOC Number	DOC Text
A.07 Rev. A	The CTS provides an introductory statement (Objective) at the beginning of this Section of the Technical Specifications which provide a brief summary of the purpose for this Section. This information is contained in the Bases Section of the ITS. This information does not establish any regulatory requirements for the systems and components addressed within this Section. Accordingly, deletion of this information does not alter any requirement set forth in the Technical Specifications. This change is administrative and consistent with the format and presentation for the ITS as provided in NUREG 1431. **CTS:** / **ITS:** 15.03.03 OBJ — DELETED 15.04.05 OBJ — DELETED
A.08 Rev. F	CTS 15.3.3.A.1.f requires the isolation valves in the discharge header of the SI system to be in the open position. ITS SR 3.5.3.1 referencing SR 3.5.2.1 requires each manual, power operated and automatic valve in the ECCS flowpath, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position at least once every 31 days. All surveillance requirements associated with an LCO are required to be met in order to fulfill the LCO. Accordingly, there is no change in requirement, making this change administrative. **CTS:** / **ITS:** 15.03.03.A.01.F — SR 3.05.03.01 - SR 3.05.02.01
A.09 Rev. A	CTS 15.3.3.A.1.g, requires the interlocks associated with the ECCS pumps and valves which are required to function during accident conditions to be operable. CTS 15.4.5.I.A.1 requires the performance of a system test during reactor shutdowns for major refueling outages, which ultimately verifies that all components received their actuation signal and actuate to their correct positions. ITS SR 3.5.3.1 referencing SR 3.5.2.3 requires each ECCS automatic valve in the flowpath that is not locked, sealed, or otherwise secured in position, to be tested to ensure it actuates to its correct position on an actual or simulated actuation signal. Similarly, SR 3.5.3.1 referencing 3.5.2.4 requires each ECCS pump to be tested to ensure it actuates on an actual or simulated actuation signal. Accordingly, both the CTS and ITS require these attributes, making this change administrative, consistent with the format and presentation of NUREG 1431. **CTS:** / **ITS:** 15.03.03.A.01.G — SR 3.05.03.01 - SR 3.05.02.03 SR 3.05.03.01 - SR 3.05.02.04

Description of Changes - NUREG-1431 Section 3.05.03

09-May-01

DOC Number	DOC Text
L.01 Rev. A	The CTS states that the ECCS systems and component listed in Specification 15.3.3.A.1.d, e, and g (RHR System, associated valves, interlocks and piping) are required to be operable prior to the reactor being made critical. CTS 15.3.3.A.1.d and e specify that two RHR pumps and heat exchangers are required to be operable. However, the Actions contained in CTS 15.3.3.A.3 for a single inoperable RHR subsystem allow the unit to be maintained greater than 350 degrees indefinitely, as long as the RHR subsystem is not being relied upon for redundancy in decay heat removal. The CTS does not provide any explicit Actions below 350 degrees unless an RHR system is being relied upon to provide redundancy in decay heat removal; therefore, entry into 15.3.0.B is required if one or both RHR loops are inoperable below 350 degrees when RHR is not being relied upon for heat removal. Entry in 15.3.0.b requires the unit to be placed into cold shutdown within 37 hours. Proposed LCO 3.5.3 will require only one train of ECCS to be operable in Mode 4 (200 to 350 degrees) which is consistent with the CTS Actions which allows a single train of RHR to be inoperable, while remaining in Mode 3 indefinitely. Proposed Condition A of LCO 3.5.3, provides a Required Action which addresses the inoperability of the ECCS function of the RHR system, recognizing its shared function relative to residual heat removal. The appropriate action in this condition is to initiate actions to restore the RHR train to operable status immediately as with no RHR subsystem available, there may be no means available to achieve a cold shutdown condition in a controlled manner making it appropriate to maintain hot conditions to maintaining the availability of the steam generators as a heat sink. Further, the core heat removal aspects of the RHR system is addressed specifically in Section 3.4 of this conversion package.

CTS:	ITS:
15.03.03.A.03	LCO 3.05.03 COND A LCO 3.05.03 COND A RA A.1
15.03.03.A.03.A	LCO 3.05.03 COND A LCO 3.05.03 COND A RA A.1
15.03.03.A.03.B	LCO 3.05.03 COND A LCO 3.05.03 COND A RA A.1
15.03.03.A.03.C	LCO 3.05.03 COND A LCO 3.05.03 COND A RA A.1

DOC Number	DOC Text
L.02 Rev. B	CTS 15.4.5.II.A.2 specifies the conditions and manner in which ECCS pump testing must be conducted (run for at least 15 minutes using the full flow test line). This requirement to run the pumps for at least 15 minutes is an arbitrary requirement with no fundamental safety basis. Therefore, these details are being removed. The proposed ITS specifies the safety objective that must be fulfilled by the surveillance tests, while leaving the details associated with testing methods and acceptance verifications to licensee control. These type of details are better suited for procedural control and are not required to be in the ITS to provide adequate protection to the public health and safety. Changes to plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards. **CTS:** 15.04.05.II.A.02 — **ITS:** DELETED
L.03 Rev. B	CTS 15.4.5.I.A.1.a specifies the conditions and manner in which ECCS testing must be conducted (RCS pressure less than or equal to 350 psig and RCS temperature less than or equal to 350 degrees, pump breakers may be placed into the "test" position), and CTS 15.4.5.I.A.2 specifies the manner in which equipment operation is to be verified (control board indication and visual indications). These details have been deleted from the Technical Specification, and moved to licensee control. These details are not necessary to describe the actual regulatory requirement (i.e. verification that equipment actuates to it correct position). These performance and acceptance details are not required to be in the ITS to provide adequate protection of public health and safety, as the actual requirement (verification of equipment actuation) has been maintained in the Technical Specifications. Changes to plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards. **CTS:** 15.04.05.I.A.01 — **ITS:** DELETED **CTS:** 15.04.05.I.A.01.A — **ITS:** DELETED **CTS:** 15.04.05.I.A.02 — **ITS:** DELETED
L.04 Rev. F	CTS 15.4.5.II.B.2 requires each manual, power operated and automatic valve necessary to ensure system operability in the emergency core cooling system, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position at least once every 31 days. ITS SR 3.5.3.1 referencing SR 3.5.2.1 requires each manual, power operated and automatic valve in the ECCS flowpath, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position once every 31 days. Requiring verification of the position of the manual, power operated and automatic valves "in the flowpath" results in a relaxation of the current requirement to verify the position of each manual, power operated and automatic valve necessary "to ensure system operability." This change is acceptable, because verifying the correct alignment for the above required valves in the flowpath provides assurance that the proper flowpath will exist for the ECCS to meet the acceptance criteria established by 10 CFR 50.46 following a LOCA. **CTS:** 15.04.05.II.B.02 — **ITS:** SR 3.05.03.01 - SR 3.05.02.01

Description of Changes - NUREG-1431 Section 3.05.03

09-May-01

DOC Number	DOC Text
LA.01 Rev. A	CTS 15.3.3.A.1.e and CTS 15.3.3.A.1.g list the RHR Heat Exchangers, valves, and piping associated with the SI and RHR Systems required to be operable to fulfill the ECCS LCO requirement. These are all attributes associated with system design and configuration, which are adequately captured through application of the definition of operability, and accordingly are still encompassed within the LCOs for ECCS. As such, these details are not required to be in the ITS to provide adequate protection of public health and safety. These attributes are discussed within the Bases for the proposed Point Beach ITS, but have been deleted from the Technical Specifications, changes to these details will be controlled in accordance with the provisions of the Bases Control Program described in Chapter 5 of the Technical Specifications. **CTS:** 15.03.03.A.01.E — **ITS:** DELETED **CTS:** 15.03.03.A.01.G — **ITS:** DELETED
LA.02 Rev. B	Not Used. **CTS:** N/A — **ITS:** N/A
LA.03 Rev. B	Not Used. **CTS:** N/A — **ITS:** N/A

DOC Number	DOC Text
M.01 Rev. A	The CTS states that the ECCS systems and components listed in Specification 15.3.3.A.1.c, f, and g (two SI pumps, SI discharge isolation valves, associated valves, interlocks, and piping) are required to be operable prior to the reactor being made critical. CTS 15.3.15.B modifies the requirement of CTS 15.3.3.A.1.c (required number of SI pumps) by stating that one of the two high head Safety Injection pumps are to be rendered inoperable whenever LTOP is required (less than 355 degrees). CTS Action 15.3.3.A.2 is contingent upon the redundant pump/function being operable as stated in CTS 15.3.3.A.2.b and c therefore the CTS does not provide an explicit action for the only required train of SI being inoperable, which results in entry into CTS 15.3.0.B. CTS 15.3.0.B requires the unit to be placed into cold shutdown within 37 hours. Proposed LCO 3.5.3 requires one train of ECCS (SI subsystem) to be operable in Mode 4, as the CTS does. Proposed Condition and Required Actions B and C of LCO 3.5.3 explicitly address the inoperability of the Safety Injection subsystem in Mode 4. The proposed actions will require the unit to be placed into Mode 5 within 24 hours if the required train of SI is not restored to operable status within one hour. This change will require the unit to be placed into cold shutdown in a shorter time frame than the CTS, and is, therefore, more restrictive. The one hour completion time for restoration of an inoperable subsystem ensures that prompt action is taken to restore the subsystem. Requiring the unit to be placed into Mode 5 is appropriate as ECCS is not required in that Mode. This change will require the unit to be placed into cold shutdown in a shorter time frame, and, as such, is more restrictive.

CTS:	ITS:
15.03.03.A.02	LCO 3.05.03 COND B LCO 3.05.03 COND B RA B.1 LCO 3.05.03 COND C LCO 3.05.03 COND C RA C.1
15.03.03.A.02.B	LCO 3.05.03 COND B LCO 3.05.03 COND B RA B.1 LCO 3.05.03 COND C LCO 3.05.03 COND C RA C.1
15.03.03.A.02.C	LCO 3.05.03 COND B LCO 3.05.03 COND B RA B.1 LCO 3.05.03 COND C LCO 3.05.03 COND C RA C.1

DOC Number	DOC Text	
M.02 Rev. A	CTS 15.4.b.II.B.1 requires a visual inspection of each containment sump suction inlet and strainer to verify that there is no restrictions or evidence of structural distress or abnormal corrosion at least each refueling outage. The proposed ITS for Point Beach both require a visual inspection of each ECCS train containment sump suction inlet for restriction by debris and inspection of the debris screen for structural distress and abnormal corrosion at least once per 18 months. The CTS requirement is the same as the proposed ITS with the exception of the specified frequency. The CTS does not define a specific frequency of performance for these Surveillance, but rather an evolution, which can vary significantly from outage to outage with no bounding limit. Accordingly, the adoption of a bounding frequency (18 months) is a more restrictive change.	
	CTS:	**ITS:**
	15.04.05.II.B.01	SR 3.05.03.01 - SR 3.05.02.05
M.03 Rev. A	CTS 15.4.5.I.A.1 and 15.4.5.I.A.2 require Safety Injection System tests to be performed during reactor shutdowns for major fuel loadings. These tests are intended to ensure that all components receive their Safety Injection (SI) signal, appropriate pump motor breakers open and close as well as verifying that all valves actuate and travel to their correct position. The proposed ITS for Point Beach (SR 3.5.3.1 reference to SR 3.5.2.3 and SR 3.5.3.1 reference to SR 3.5.2.4) will require each ECCS pump and each automatic valve in the flowpath that is not locked, sealed, or otherwise secured in position, either start or actuates to its correct position, as applicable, on an actual or simulated actuation signal at least once every 18 months. The CTS and the ITS impose the same testing, but the CTS does not define a specific frequency of performance for these Surveillance, but rather an evolution, which can vary significantly from outage to outage with no bounding limit. Accordingly, the adoption of a bounding frequency (18 months) is a more restrictive change.	
	CTS:	**ITS:**
	15.04.05.I.A.01	SR 3.05.03.01 - SR 3.05.02.03 SR 3.05.03.01 - SR 3.05.02.04
	15.04.05.I.A.02	SR 3.05.03.01 - SR 3.05.02.03 SR 3.05.03.01 - SR 3.05.02.04
M.04 Rev. A	As addressed in Description of Change A.2 of this LCO, the CTS requires one SI and one RHR pump system to be operable in the equivalent of ITS Mode 4. However, the CTS does not require the SI and RHR pump systems to be associated with the same train of ECCS. The Point Beach ECCS piping design is capable of supporting cross-train operation of the residual heat removal and safety injection subsystems. However, cross-train operation in the post accident recirculation mode of operation requires local valve manipulations which is not currently addressed by the emergency operating procedures. As such, ITS LCO 3.5.3 will require a single Train of ECCS to be operable, thereby requiring the SI and RHR pump systems to be in the same ECCS Train.	
	CTS:	**ITS:**
	15.03.03.A.01.C	LCO 3.05.03
	15.03.03.A.01.D	LCO 3.05.03

A.1

< See Section 3.6 >

A.1

SR 3.5.3.1 - SR 3.5.2.2

containment spray pumps shall be tested in accordance with the Inservice Test Program.

2. Acceptable levels of performance shall be that the pumps start, reach their required developed head at, ~~and operate for at least fifteen minutes on the full-flow test lines.~~

L.2

B Errata #50

B. Other

18 months

M.2

SR 3.5.3.1 - SR 3.5.2.5

1. ~~At least every refueling~~, verify by visual inspection each containment sump suction inlet is not restricted by debris and the debris strainers show no evidence of structural distress or abnormal corrosion.

F Errata #165

L.4

SR 3.5.3.1 - SR 3.5.2.1

2. Verify each manual, power operated, and automatic valve necessary to insure system operability in the emergency core cooling and containment spray systems that is not locked, sealed, or otherwise secured in position, is in the correct position at least once every 31 days.

< See Section 3.6 >

A.3

Basis

The Safety Injection System and the Containment Spray System are principal plant Safety Systems that are normally inoperative during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is therefore to combine systems tests to be performed during refueling shutdowns, with more frequent component tests, which can be performed during reactor operation.

No Significant Hazards Considerations - NUREG-1431 Section 3.05.03

09-May-01

NSHC Number	NSHC Text
A Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change involves reformatting and rewording of the current Technical Specifications. The reformatting and rewording process involves no technical changes to existing requirements. As such, this change is administrative in nature and does not impact initiators of analyzed events or assumed mitigation of accident or transient events. Therefore, this change does not increase 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will not impose any new or eliminate any old requirements. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The proposed change will not significantly reduce the margin of safety because it has no impact on any safety analysis assumptions. This change is administrative. As such, there is no technical change to the requirements and, therefore, there is no reduction in the margin of safety.

No Significant Hazards Considerations - NUREG-1431 Section 3.05.03

09-May-01

NSHC Number	NSHC Text
L.01 Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? This change does not result in any hardware changes. The components covered by this Technical Specification are not assumed to be initiators of any analyzed event. The Shutdown Actions, Mode of Applicabilities, and required number of ECCS components are not precursors to any analyzed events. Therefore the probability associated with analyzed events is unchanged. The proposed Applicabilities, minimum equipment requirements and shutdown actions are based on stable unit conditions associated with MODE 4, the reduced thermal energy in the core, sufficient time for manual actuation of the remaining ECCS pumps to mitigate a Design Basis Accidents as necessary, and the assumption that single failures in the ECCS system are not assumed below Mode 3. As such, there is no significant increase in the consequence 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change establishes Applicabilities, Required Actions, and complements of components reflective of assumptions made in the Accident Analysis. As such, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? This change proposes equipment Applicabilities, minimum numbers of components/subsystems and shutdown actions based on stable unit conditions associated with MODE 4, the reduced thermal energy in the core, and sufficient time for manual actuation of the remaining ECCS pumps, assuming no single failure within the ECCS subsystem. In addition, this change is reflective of assumptions made in the accident analysis for Point Beach. Therefore, this change does not involve a significant reduction in a margin of safety.

NSHC Number	NSHC Text
L.02 Rev. B	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. The proposed change results in the deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? The deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety, does not result in a significant reduction in the margin of safety.

NSHC Number	NSHC Text
L.03 Rev. B	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. The proposed change results in the deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? The deletion of details which are not necessary to describe the actual regulatory requirement, or provide adequate protection of the public health and safety, does not result in a significant reduction in the margin of safety.

NSHC Number	NSHC Text
L.04 Rev. F	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change results in a relaxation of requirements such that only the ECCS manual, power operated and automatic valves in the flowpath that are not locked, sealed, or otherwise secured in position are verified to be in the correct alignment. The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. Accordingly, there will be no significant change in the probability or consequences of accidents previously evaluated. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not involve any physical alteration of plant systems, structures or components, nor does it alter parameters governing normal plant operation. The proposed change does not introduce a new mode of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created. 3. Does this change involve a significant reduction in a margin of safety? This change does not involve a significant reduction in a margin of safety because the ability of ECCS to perform its safety functions is still verified. The intent of the surveillance requirement has not been altered and does not result in a reduction in the margin of safety.

NSHC Number	NSHC Text
LA Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change relocates requirements from the Technical Specifications to the Bases, FSAR, or other plant controlled documents. The Bases and FSAR will be maintained using the provisions of 10 CFR 50.59. In addition to 10 CFR 50.59 provisions, the Technical Specifications Bases are subject to the change process in the Administrative Controls Chapter of the ITS. Plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards. Changes to the Bases, FSAR, or other plant controlled documents will be evaluated in accordance with the requirements of the Bases Control Program in Chapter 5.0 of the ITS, 10 CFR 50.59, or plant administrative processes. Therefore, no increase in the probability or consequences of an accident previously evaluated will be allowed. 2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change will not impose any different requirements and adequate control of the information will be maintained. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The proposed change will not reduce a margin of safety because it has no impact on any safety analysis assumptions. In addition, the requirements to be moved from the Technical Specifications to the Bases, FSAR, or other plant controlled documents are as they currently exist. Future changes to the requirements in the Bases, FSAR, or other plant controlled documents will be evaluated in accordance with the requirements of 10 CFR 50.59, the Bases Control Program in Chapter 5.0 of the ITS, or the applicable plant process and no reduction in a margin of safety will be allowed.

NSHC Number	NSHC Text
M Rev. A	In accordance with the criteria set forth in 10 CFR 50.92, PBNP has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion. 1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated? The proposed change provides more restrictive requirements for operation of the facility. These more stringent requirements do not result in operation that will increase the probability of initiating an analyzed event and do not alter the assumptions relative to the mitigation of an accident or transient event. These more restrictive requirements continue to ensure process variables, structures, systems and components are maintained consistent with the safety analyses. Therefore, this change does not increase 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? The proposed change does not require a physical alteration of the plant (no new or different type of equipment will be installed) or changes in parameters governing normal plant operation. The proposed change does impose different requirements. However, these changes are consistent with assumptions made in the safety analysis. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated. 3. Does this change involve a significant reduction in a margin of safety? The imposition of more restrictive requirements either has no affect on or increases the margin of safety. Each change is providing additional restrictions to enhance plant safety. These changes are consistent with the safety analysis. Therefore, this change does not involve a reduction in a margin of safety.

Description of Changes - NUREG-1431 Section 3.06.03

09-May-01

DOC Number	DOC Text	
A.06 Rev. F	CTS 15.3.6.A.1.c.1 requires the containment purge supply and exhaust valves to be locked closed (control board locking devices) however, a single containment purge supply or exhaust valve may be opened to allow repair of a penetration which is leaking in excess of that allowed by the Containment Leakage Rate Testing Program. ITS SR 3.6.3.1 requires each containment purge supply and exhaust valve to be closed with the control switch locked, but will allow one containment purge valve to be opened in a penetration flowpath to perform leakage rate corrective maintenance. This change is administrative.	
	CTS:	**ITS:**
	15.03.06.A.01.C	SR 3.06.03.01
	15.03.06.A.01.C.01	SR 3.06.03.01
A.07 Rev. A	The CTS does not require performance of the surveillance which verifies closure of the containment purge supply and exhaust valve when the unit is in the cold shutdown or refueling shutdown condition; however, performance of this surveillance prior to exceeding 200 degrees is required if the test had not been performed within its required frequency of 31 days. The Mode of Applicability for this LCO and hence its associated Surveillance Requirement has been revised to Modes 1, 2, 3, and 4 (greater than or equal to 200 degrees) as addressed in Description of Change A.3 and L.1 of this LCO conversion package. ITS SR 3.0.4 precludes entry into a Mode or specified condition unless all surveillances associated with the LCO are met (inclusive of the specified interval). Accordingly, the CTS requirement which requires the containment purge valves be verified locked closed prior to exceeding 200 degrees is not necessary in the ITS. This requirement is adequately addressed through the defined Mode of Applicability for the purge valves in addition to the general usage rule associated with LCO SR 3.0.4. Deletion of this CTS item is administrative.	
	CTS:	**ITS:**
	15.04.01 T 15.04.01-02 23 (9)	DELETED
A.08 Rev. A	The Bases of the current Technical Specifications for this section have been completely replaced by revised Bases that reflect the format and applicable content of PBNP ITS, consistent with the Standard Technical Specifications for Westinghouse Plants, NUREG-1431. The revised Bases are as shown in the PBNP ITS Bases.	
	CTS:	**ITS:**
	BASES	B 3.06.03

F
Errata #158

with the control switch locked

10

15

1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each ~~[42] inch purge~~ purge supply and exhaust valve is ~~sealed~~ closed with the control switch locked, except for one purge valve in a penetration flow path ~~while in Condition E of this LCO.~~ to perform leakage rate corrective maintenance.	31 days
~~SR 3.6.3.2~~	~~Verify each [8] inch purge valve is closed, except when the [8] inch containment purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.~~	~~31 days~~
SR 3.6.3.~~3~~ 2	------------------NOTE------------------ Valves and blind flanges in high radiation areas may be verified by use of administrative controls. -- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days

2 2 7 9 6

(continued)

and not locked sealed or otherwise secured

Approved TSTF 45

1

BASES

ACTIONS (Continued)

within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

2

10

with their control board switches locked

F

Erratra #158

SURVEILLANCE REQUIREMENTS

[SR 3.6.3.1

15

supply and exhaust

Each ~~[42] inch~~ containment purge valve is required to be verified ~~sealed~~ closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close ~~during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness.~~ The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. [4]), related to containment purge valve use during plant operations. In the event purge valve leakage ~~requires entry into Condition E, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs.~~]

Replace with Insert B 3.6.3-6

10

9

of

in excess of that allowed by the Containment Leakage Rate Testing Program,

6

3

2

~~[SR 3.6.3.2~~

~~This SR ensures that the minipurge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the minipurge valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The minipurge valves are capable of~~

7

LCO 3.6.3 BASES INSERTS

Insert B 3.6.3-4:

No specific containment isolation time was assumed in the LOCA analysis. However, containment isolation is an implicit assumption in maintaining containment leakage within it's design leakage rate, L_a, and containment back pressure relative to RCS blowdown rate.

Insert B 3.6.3-5:

The automatic power operated isolation valves are required to actuate to the closed position on an automatic isolation signal. The containment purge supply and exhaust valves must be maintained closed with their control switches in the locked closed position. The valves covered by this LCO are listed in the FSAR (Ref. 2).

Insert B 3.6.3-6:

under LOCA conditions. Therefore, these valves are required to be in the closed position with their control switches locked during MODES 1, 2, 3, and 4. F Erratra #158

Insert B 3.6.3-7:

Position verification, when necessary in accordance with the required actions and/or surveillance requirements, is still required for these valves. B RAI 3 6 3-7

Insert B 3.6.3-8:

Note 2 applies to isolation devices that are locked sealed or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

Insert B 3.6.3-9:

Required Action E.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each purge supply and exhaust valve is closed with the control switch locked, except for one purge valve in a penetration flow path to perform leakage rate corrective maintenance.	31 days
SR 3.6.3.2	--------------------------NOTE------------------------ Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days

F
Errata #158

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each containment purge supply and exhaust valve is required to be verified closed with their control board switches locked at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close under LOCA conditions. Therefore, these valves are required to be in the closed position with their control switches locked during MODES 1, 2, 3, and 4. The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 3), related to containment purge valve use during plant operations. In the event of purge valve leakage in excess of that allowed by the Containment Leakage Rate Testing Program, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs.

F
Errata #158

F
Errata #158

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not

Description of Changes - NUREG-1431 Section 3.06.06

09-May-01

DOC Number	DOC Text	
A.01 Rev. A	In the conversion of Point Beach current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the Standard Technical Specifications, Westinghouse Plants, NUREG-1431, Revision 1 (i.e., Improved Standard Technical Specifications (ISTS)).	
	CTS:	**ITS:**
	15.03.03.B.02	LCO 3.06.06 COND B
		LCO 3.06.06 COND B RA B.1
	15.03.03.B.02.A	LCO 3.06.06 COND C
		LCO 3.06.06 COND C RA C.1
	15.03.03.B.02.B	LCO 3.06.06 COND A
	15.04.02.B.03	SR 3.06.06.04
	15.04.05.I.B.03	SR 3.06.06.09
	15.04.05.I.C.01	SR 3.06.06.05
		SR 3.06.06.08
	15.04.05.I.C.02	SR 3.06.06.02
	15.04.05.II.A.01	SR 3.06.06.04
	15.04.05.II.A.02	SR 3.06.06.04
	NEW	LCO 3.06.06
A.02 Rev. A	The CTS provides an introductory statement (Applicability) which simply states which systems/components are addressed within a given section. This same information, while worded differently, is contained within the title of each ITS LCO. Accordingly, this change is a change in format with no change in technical requirement.	
	CTS:	**ITS:**
	15.03.03 APPL	LCO 3.06.06
	15.04.05 APPL	LCO 3.06.06
A.03 Rev. A	The CTS provides an introductory statement (Objective) at the beginning of this Section of the Technical Specifications which provide a brief summary of the purpose for this Section. This information is contained in the Bases Section of the ITS. This information does not establish any regulatory requirements for the systems and components addressed within this Section. Accordingly, deletion of this information does not alter any requirement set forth in the Technical Specifications. This change is administrative and consistent with the format and presentation for the ITS as provided in NUREG 1431.	
	CTS:	**ITS:**
	15.03.03 OBJ	DELETED
	15.04.05 OBJ	DELETED

Description of Changes - NUREG-1431 Section 3.06.06

09-May-01

DOC Number	DOC Text	
A.04 Rev. A	The CTS 15.3.3.B.1 requires the Containment Spray and Containment Fan Coolers to be operable prior to the reactor being made critical. However, CTS 15.3.3.B.2 requires the unit to be placed into Hot Shutdown (ITS Mode 3) within 6 hours and Cold Shutdown (ITS Mode 5) within 36 hours, if these systems are inoperable in excess of the allowable outage time, implying an Applicability of Modes 1, 2, 3, and 4 (ITS Modes). Proposed LCO 3.6.6 will require the Containment Spray System and the Containment Fan Cooler Units to be operable in Modes 1, 2, 3, and 4. This change is considered administrative as it is clarifying an ambiguous LCO Applicability and Action Statements.	
	CTS:	**ITS:**
	15.03.03.B.01	LCO 3.06.06
A.05 Rev. A	CTS 15.3.3.B.1.b requires two containment spray pumps and CTS 15.3.3.B.1.d establishes a requirement to maintain all valves and piping associated with the containment spray pumps operable. CTS 15.3.3.B.1.b and CTS 15.3.3.B.1.d lists components associated with system design and configuration which ultimately define what constitutes a "train" of Containment Spray. In changing the terminology used to two "trains" of Containment Spray the component listed in CTS 15.3.3.B.1.b and 15.3.3.B.1.d are captured. Further, valves are addressed through the valve testing requirements specified in the proposed ITS SR 3.6.6.5 and the Inservice Testing Program (IST-Specification 5.5.8), while pump testing is addressed through SR 3.6.6.3 and the IST Program. This change is administrative.	
	CTS:	**ITS:**
	15.03.03.B.01.B	LCO 3.06.06
	15.03.03.B.01.D	LCO 3.06.06
A.06 Rev. A	CTS 15.3.3.B.1.c requires four accident fan-cooler units to be operable and CTS 15.3.3.B.1.d establishes a requirement to maintain all valves and piping associated with the accident fan cooler units operable. ITS LCO 3.6.6 will continue to require four containment fan cooler to be operable. Fan cooler operability will be verified by SR 3.6.6.1 while the requirement to maintain the valves associated with the fan cooler unit operable will be addressed within SR 3.6.6.4 and the Inservice Testing Program (Specification 5.5.8). This change is administrative.	
	CTS:	**ITS:**
	15.03.03.B.01.C	LCO 3.06.06
	15.03.03.B.01.D	LCO 3.06.06

DOC Number	DOC Text	
A.07 Rev. A	CTS Action 15.3.3.B.2 allows the inoperability of either one containment spray pump, or any valve which supports the containment spray system. However, CTS 15.3.3.B.2.c provides an allowance for the valves associated with an inoperable containment spray pump to be inoperable concurrent with their respective pump's inoperability. The proposed ITS has rephrased the LCO for the containment spray pumps, calling for two "trains" of containment spray to be operable. Similarly, the Conditions and Required Actions have been rephrased to allow entry whenever a "train" of containment spray becomes inoperable. The valves associated with an inoperable containment spray pump are part of that system's train, therefore, the ITS condition of a train inoperable is equivalent to CTS items 15.3.3.B.2 as modified by CTS 15.3.3.B.2.c. Accordingly, while phrased differently, the ITS will continue to allow the valves associated with an inoperable containment spray pump to be inoperable concurrent with the pump, making this change administrative.	
	CTS:	**ITS:**
	15.03.03.B.02.C	LCO 3.06.06 COND A
A.08 Rev. A	The CTS allows component inoperabilities for up to 72 hours providing that the redundant or remaining components are operable (e.g. second containment spray pump, remaining two accident fan coolers, or redundant valves are operable). If the redundant or remaining components are not operable, the CTS requires entry into LCO 15.3.0.b which requires the unit to be placed into hot shutdown (ITS Mode 3) within 7 hours and cold shutdown (ITS Mode 5) within 37 hours. The ITS contains this same concept, specifying Conditions and Actions which only address the loss of a single train of containment spray or loss of up to two accident fan coolers. The ITS does not explicitly state that the redundant or remaining components must be operable; however, if more than the number of components specified in the condition are inoperable (meaning that the redundant or remaining components are inoperable), the ITS will require entry into LCO 3.0.3 which requires the unit to be placed into Mode 3 within 7 hours, Mode 4 within 13 hours, and Mode 5 within 37 hours. While the shutdown time limits are more restrictive than the existing Technical Specifications, the concept of assuring that the redundant or remaining components are operable during the 72 hour restoration period allowed for an inoperable containment spray pump, accident fan cooler, or valve required to support these systems has been maintained. This change is administrative.	
	CTS:	**ITS:**
	15.03.03.B.02.A	LCO 3.06.06 COND C
	15.03.03.B.02.B	LCO 3.06.06 COND A
	15.03.03.B.02.C	LCO 3.06.06 COND A
A.09 Rev. A	CTS 15.3.3.B.2.c allows any valve required for the functioning of the containment spray pumps or containment coolers to be inoperable for up to 72 hours. Relative to the containment spray pumps, this Action has been incorporated into Condition A of the ITS as the valves are a subset of the containment spray train itself. The containment fan cooler outlet valves have been addresses in Condition D of the proposed ITS. Both of these Actions require restoration within a 72 hour period, Accordingly, this change is administrative.	
	CTS:	**ITS:**
	15.03.03.B.02.C	LCO 3.06.06 COND A

Description of Changes - NUREG-1431 Section 3.06.06

09-May-01

DOC Number	DOC Text	
A.10 Rev. A	CTS 15.3.3.B.2 requires the unit to be placed into hot shutdown (ITS Mode 3) within 6 hours and cold shutdown (ITS Mode 5) within 36 hours if one or two accident fan cooler units, or their associated valves are inoperable in excess of 72 hours. The ITS will similarly require the unit to be placed into Mode 3 within 6 hours and Mode 5 within 36 hours if accident fan cooler(s) (Condition C) or their associated service water outlet valves (Condition D) are not restored to operable status within 72 hours	
	CTS:	**ITS:**
	15.03.03.B.02	LCO 3.06.06 COND E
		LCO 3.06.06 COND E RA E.1
		LCO 3.06.06 COND E RA E.2
A.11 Rev. A	The Bases of the current Technical Specifications for this section have been completely replaced by revised Bases that reflect the format and applicable content of PBNP ITS, consistent with the Standard Technical Specifications for Westinghouse Plants, NUREG-1431. The revised Bases are as shown in the PBNP ITS Bases.	
	CTS:	**ITS:**
	BASES	B 3.06.06

Description of Changes - NUREG-1431 Section 3.06.06

09-May-01

DOC Number	DOC Text
L.01 Rev. A	CTS Action 15.3.3.B.2 allows the inoperability of only one of the following at a given time; 1) one or two accident containment fan cooler(s), 2) one containment spray pump, or 3) any valve which supports the containment fan coolers. The proposed ITS will allow any combination of aforementioned components to be inoperable concurrently. The Point Beach containment pressure analysis assumed the operation of a single containment spray pump in combination with two accident fan coolers. The ITS preserves these assumptions and will require a plant shutdown in accordance with LCO 3.0.3 (Mode 3 in 7 hours, Mode 4 in 13 hours, and Mode 5 in 37 hours) if the minimum complement of components assumed are not available. This change affords two relaxation's to the CTS. The first relaxation allows the valves and piping associated with an inoperable accident fan cooler to be inoperable concurrent with an inoperable accident fan cooler(s). This is considered acceptable based on maintaining at least two fan coolers operable. A single inoperable service water valve represents a failure to met single failure criteria; however, the remaining valve assures that the design function of the fan coolers is preserved. One service water outlet valve is adequate to provide 100% of the assumed flow rate to all four accident fan coolers. Any combination of the above two inoperabilities (fan coolers and service water outlet valves) will still leave at least two fan coolers operable, which is the minimum assumed in the containment pressure analysis. The second relaxation allows operation with a containment spray pump and up to two accident fans cooler inoperable concurrently. This condition is considered acceptable because at least two fan cooler units and one containment spray train operable will continue to be available for accident mitigation. 72 hours for all the above combinations is considered acceptable, as functionality is maintained; only single failure capability has been lost. 72 hours is consistent with the loss of single failure capability for other systems of equivalent importance. **CTS:** 15.03.03.B.02 **ITS:** DELETED
L.02 Rev. A	CTS 15.3.3.B.2 requires the unit to be placed into Hot Shutdown (ITS Mode 3) within 6 hours and Cold Shutdown, (ITS Mode 5) within 36 hours if the containment spray pumps or their associated valves and piping are not restored to operable status within the allowed completion time. The ITS will require the unit to be placed into Mode 3 within 6 hours and Mode 5 within 84 hours, extending the time allowed to reach Mode 4 by 48 hours. The extended interval allows additional time to restore the inoperable containment spray train to operable status. This additional time is acceptable based on the conservatism inherent to the unit being placed in Mode 3. Dose considerations (offsite and control room) are projected based on a core operating at 102% of rated power and the containment pressure analysis is based upon a higher energy state (temperature) for the reactor coolant system. The reduced consequences from these specifics alone are judged to offset the increased time allowed to operate in a condition capable of event mitigation, but incapable of a single failure. **CTS:** 15.03.03.B.02 **ITS:** LCO 3.06.06 COND B RA B.2

DOC Number	DOC Text
L.03 Rev. A	CTS 15.4.5.I.B.3 requires the containment spray nozzles to be checked to ensure they are not obstructed at intervals not exceeding five years. The proposed ITS (SR 3.6.6.8) will require performances of this test once every 10 years, plus the 25% surveillance frequency extension allowed through application of SR 3.0.2 (a maximum of 12.5 years). This increase in frequency is considered acceptable based on the passive nature of the components. The containment spray nozzles are located near the top of the containment dome, in an area not subject to damage from personnel nor other components and debris. The containment spray nozzles are configured as "dry piping" and accordingly, are not subject to a harsh environment (contact with acids, caustics or other chemicals) during normal operation which could introduce significant age related degradation. **CTS:** 15.04.05.I.B.03 — **ITS:** SR 3.06.06.09
L.04 Rev. B	CTS 15.4.5.I.B.1 and CTS 15.4.5.I.B.2 provides details on surveillance testing which are not necessary to describe the actual regulatory requirement. The requirement to run the pumps for at least 15 minutes in accordance with CTS 15.4.5.II.A.2 is an arbitrary requirement with no fundamental safety basis. Therefore, these details are being removed. The proposed ITS specifies the safety objective that must be fulfilled by the surveillance tests, while leaving the details associated with testing methods and acceptance verifications to licensee control. These type of details are better suited for procedural control and are not required to be in the ITS to provide adequate protection to the public health and safety. Changes to plant procedures and other plant controlled documents are subject to controls imposed by plant administrative procedures, which endorse applicable regulations and standards. **CTS:** 15.04.05.I.B.01 — **ITS:** DELETED **CTS:** 15.04.05.I.B.02 — **ITS:** DELETED **CTS:** 15.04.05.II.A.02 — **ITS:** DELETED
L.05 Rev. C	CTS 15.4.5.I.B.1 requires the Containment Spray System test to be initiated by tripping the normal actuation instrumentation. The proposed ITS requirement in SR 3.6.6.5 and SR 3.6.6.6 allow initiation by an actual or simulated signal. The proposed ITS is less restrictive because it allows either a simulated or an actual signal. This change is insignificant because the actuation instrumentation for this system is appropriately surveilled in accordance with the requirements in Section 3.3 of the proposed ITS. **CTS:** 15.04.05.I.B.01 — **ITS:** DELETED

Description of Changes - NUREG-1431 Section 3.06.06

09-May-01

DOC Number	DOC Text	
L.06 Rev. F	CTS 15.4.5.II.B.2 requires each manual, power operated and automatic valve necessary to ensure system operability in the containment spray systems, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position at least once every 31 days. ITS SR 3.6.6.1 requires each manual, power operated and automatic valve in the containment spray flowpath, that is not locked, sealed, or otherwise secured in position, to be verified to be in its correct position once every 31 days. Requiring verification of the position of the manual, power operated and automatic valves "in the flowpath" results in a relaxation of the current requirement to verify the position of each manual, power operated and automatic valve necessary "to ensure system operability." This change is acceptable, because verifying the correct alignment of the above required valves in the flowpath provides assurance that the proper flowpath will exist for the Containment Spray System to limit the temperature and pressure that could be experienced following a LOCA.	
	CTS:	**ITS:**
	15.04.05.II.B.02	SR 3.06.06.01
LA.01 Rev. B	CTS 15.4.5.I.C.2 specifies acceptable performance of the containment fan cooler accident fan test shall be that the fan starts and running current is verified. This acceptance criteria is relocated to the Bases. This detail is not required to be in the technical specifications to provide adequate protection to the public health and safety. The requirement that the containment fan cooler accident fan be tested to verify operability is being maintained.	
	CTS:	**ITS:**
	15.04.05.I.C.02	B 3.06.06
M.01 Rev. A	CTS 15.3.3.B.1 contains a provision exempting the requirement to maintain the Containment Spray and Containment Fan Coolers operable during low power physics testing. This provision has been deleted in the proposed Technical Specifications. Low power physics testing in the Improved Technical Specifications is a subset of Mode 2. While Mode 2 is typically a non limiting Mode, the operability requirements of these systems are independent of physics testing, accordingly this provision has been deleted. This change represents a more restrictive change as it involves the deletion of a flexibility that currently exists.	
	CTS:	**ITS:**
	15.03.03.B.01	DELETED

DOC Number	DOC Text
M.02 Rev. A	CTS 15.4.5.I.B.1 requires the performance of a containment spray system test "during reactor shutdowns once every major fuel reloading". This test is intended to verify proper operation of all component which are actuated on a containment spray actuation signal. This testing has been translated to ITS SR 3.6.6.4 and SR 3.6.6.5 which are performed on a frequency of once every 18 months. The CTS frequency is not specific in that it is tied to a plant evolution ("during reactor shutdowns for major fuel reloading") as opposed to an explicit performance interval. Requiring performance of these surveillances on a fixed frequency of 18 months is more restrictive, as the previous frequency has no bounding limit and is considered vague in regards to what constitutes a "major fuel reloading". An 18 month interval for actuation testing is more prescriptive that the CTS and is acceptable based on industry reliability data. **CTS:** 15.04.05.I.B.01 **ITS:** SR 3.06.06.05, SR 3.06.06.06
M.03 Rev. A	CTS 15.4.5.I.C.1 requires each fan cooler and fan cooler service water outlet bypass valve to be tested at each refueling to verify proper operation of the backdraft dampers and valves. These tests has been translated to ITS SR 3.6.6.7 and SR 3.6.6.4 respectively, which are performed on a frequency of once every 18 months. The CTS frequency is not specific in that it is tied to a plant evolution (each refueling) as opposed to an explicit performance interval. Requiring performance of these surveillances on a fixed frequency of 18 months is more restrictive, as the previous frequency has no bounding limit. An 18 month interval for verification of damper function is acceptable based on past performance data. **CTS:** 15.04.05.I.C.01 **ITS:** SR 3.06.06.05, SR 3.06.06.08
M.04 Rev. A	The CTS require the containment cooler unit's accident fan to be operable, for which auto start capability from a safety injection signal is an attribute; however, the CTS does not contain any surveillance requirement which verifies this attribute. Accordingly, the proposed ITS contains a surveillance requirement, SR 3.6.6.6, which specifically requires verification of the auto start capability associated with the containment cooler unit's accident fan on an 18 month frequency. This surveillance and its associated frequency of performance are consistent with the other equipment actuation tests, and is considered acceptable based on industry reliability data. The addition of this surveillance is a more restrictive change. **CTS:** NEW **ITS:** SR 3.06.06.07

DOC Number	DOC Text	
M.05 Rev. B	The CTS require each containment fan cooler unit to be operable. Implicit is the assumption that each fan cooler unit can achieve a cooling water flow rate of greater than or equal to that assumed in the accident analysis when at least one fan cooler service outlet isolation valve is opened. The CTS does not contain any surveillance requirement which verifies containment fan cooler service water flow rate. Accordingly, the proposed ITS contains a surveillance requirement, SR 3.6.6.3, which specifically requires verification that each containment fan cooler unit can achieve it required flow rate on an 31 day frequency. The proposed ITS will require flow to be verified to be within design limits, retaining the limitations themselves within licensee control, because fan cooler unit service water flow is not a fixed limit. Flow rate must be verified to meet a specific value with cooling coil differential pressure within a specified range to ensure that the cooling coils will achieve a flow rate greater than or equal to that assumed in the accident analysis. The Service Water limits are derived using system flow models. This difference is based on the design of the Service Water system, which is discussed in further detail in Justification for Deviation 1 of the Service Water LCO, 3.7.8. Based on the number of variable involved, and the limits themselves being based on system configuration, control over the limits themselves are proposed to be maintained within licensee control.	
	CTS:	**ITS:**
	NEW	SR 3.06.06.03
M.06 Rev. A	The CTS does not contain a time limit for the total time that the LCO requirements for containment cooling can be not met. The proposed ITS time limit of 144 hours is consistent with the NUREG-1431 convention that the total time is consistent with the combination of the individual completion times. In this case, fan cooler operability completion time is 72 hours and the spray pump operability completion time is 72 hours, thus 144 hours total time is appropriate.	
	CTS:	**ITS:**
	15.03.03.B.02.A	LCO 3.06.06 COND C RA C.1
	15.03.03.B.02.B	LCO 3.06.06 COND A RA A.1
	15.03.03.B.02.C	LCO 3.06.06 COND D RA D.1

A.1

SR 3.6.6.4

containment spray pumps shall be tested in accordance with the Inservice Test Program.

2. Acceptable levels of performance shall be that the pumps start, reach their required developed head at, and operate for ~~at least~~ fifteen ~~minutes on the full~~-flow test ~~lines~~.

L.4

B RAI 3.6.6-5

B. Other

< See LCO 3.5.2 >

1. **At least every refueling, verify by visual inspection each containment sump suction inlet is not restricted by debris and the debris strainers show no evidence of structural distress or abnormal corrosion.**

L.6

SR 3.6.6.1

2. Verify each manual, power operated, and automatic valve necessary to insure system operability in the emergency core cooling and containment spray systems that is not locked, sealed, or otherwise secured in position, is in the correct position at least once every 31 days.

F Errata #165

< See Section 3.5 >

Basis

The Safety Injection System and the Containment Spray System are principal plant Safety Systems that are normally inoperative during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is therefore to combine systems tests to be performed during refueling shutdowns, with more frequent component tests, which can be performed during reactor operation.

A.11