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AUTH.NAME AUTHOR AFFILIATION
BASKIN,K.P. Southern California Edison Co.
RECIP.NAME RECIPIENT AFFILIATION
MIRAGLIA,F. Licensing Branch 3

SUBJECT: Forwards summary of Tech Spec open items & marked-up Tech Specs re effluent limitations, monitoring requirements & demonstration studies, based on review of environ protection plan. See RPTS (Tech Specs)

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	NRR/DSI/AEB	26	1	1	NRR/DSI/ASB	27	1	1
	NRR/DSI/CPB	10	1	1	NRR/DSI/CSB	09	1	1
	NRR/DSI/ETSB	12	1	1	NRR/DSI/ICSB	16	1	1
	NRR/DSI/PSB	19	1	1	NRR/DSI/RAB	22	1	1
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Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

K. P. BASKIN
MANAGER OF NUCLEAR ENGINEERING,
SAFETY, AND LICENSING

TELEPHONE
(213) 572-1401

Director, Office of Nuclear Reactor Regulation
Attention: Mr. Frank Miraglia, Branch Chief
Licensing Branch No. 3
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Subject: Docket Nos. 50-361 and 50-362
San Onofre Nuclear Generating Station
Units 2 and 3

Appendix A Technical Specifications for San Onofre Nuclear Generating Station, Units 2 and 3 were distributed for proof and review within the NRC and to SCE on October 21, 1981. We have completed our review of the proof and review Technical Specifications (including the revised pages from the NRC Licensing Guidance Branch dated November 2 and November 9, 1981). Changes to the Technical Specifications that we propose are enclosed with this letter. As summarized in Enclosure 1, these changes address the 33 technical specification open items identified in telephone conversations between Mark Medford of our company and Harry Rood, NRC Project Manager.

In addition, by letter dated March 27, 1981 to Messrs. Robert Dietch, Southern California Edison Company, and D. W. Gilman, San Diego Gas & Electric Company, the NRC submitted a draft of the Environmental Protection Plan (EPP) for our review and comment. We have completed our review of the draft EPP.

As stated in the EPP, aquatic issues at San Onofre Nuclear Generating Station are addressed by the effluent limitations, monitoring requirements and demonstration studies contained in the effective NPDES permit issued by the California Regional Water Quality Control Board - San Diego Region. The NRC will rely on that agency for regulation of matters involving water quality and aquatic biota.

Therefore, we do not see any legal or regulatory basis for the EPP. In addition, with regard to Section 5.4, Plant Reporting Requirements;

1) There are no activities required by EPP Section 4.2. Therefore, there are no results to analyze and report;

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S.1.60

2) The "EPP noncompliances" are vague and subject to individual interpretation. Clarification is needed if anything is to be reported; and ,

3) With the exception clause included in Section 5.4.2, nonroutine reports will consist almost exclusively of reports that are required by the NPDES permit.

It is our belief that the NRC need to be aware of environmental activities and occurrences at San Onofre Nuclear Generating Station, Units 2 and 3, can most easily and completely be satisfied by a Company commitment to submit, to the NRC Regional Director, copies of all correspondence and reports required by the effective NPDES permit. Accordingly, such a commitment is proposed in lieu of the NRC proposed EPP.

If you have any question, concerning these matters please call me.

Very truly yours,

W P Barker

Enclosures

50-361

SUMMARY OF SONGS

TECHNICAL SPECIFICATION OPEN ITEM

Received wth ltr dtd 11/10/81

SUMMARY OF SONGS 2 TECHNICAL SPECIFICATION OPEN ITEMS

1. CPC Addressable Constants - The SER Supplement 2 Section 7.2 requirements have been incorporated.

2. (Previously resolved)

3. (Previously resolved)

4. Definitions of CEA "Full Out" - The necessary clarification has been incorporated.

5. DNBR Penalty Factors - We accept the SER values pending NRC approval of the CE topical report upon which the CE values have been based.

6. Delete T_{avg}; Add Tc, Pressure, ASI Specs: Incorporated.

7. RPS Table and ESF Table Review for Validity: Complete. Changes as marked.

8. RPS Response Times, not consistent with FSAR - FSAR change to be submitted in the next revision.

9. ESF Table Trip Value Revisions - Trip values have been revised to the most recent data.

10. (Previously resolved)

11. Seismic Monitor Channel - "Accessible": This change has been provided together with appropriate justification in our comments to Section 3/4.3.

12. (Previously resolved)

13. Heat-Up and Cool-Down Curves, Additions: Not required; the provided curves contain all required information.

14. LTOP Revisions: Incorporated.

15. HPSI & LPSI Developed Head and Flowrates: Incorporated.

16. (Previously resolved)

17. NaOH 5 Year Test Flow Rates: This requirement pertains only to eductor-type spray chemical addition systems; applicable ASME XI Inservice Testing requirements for the SONGS 2 pumped system have been incorporated instead.

18. Snubber Corrections and Tables: Incorporated.

19. "On" for Filter System Heaters: Accepted.

20. Offsite Transmission Network Surveillance: Applicable requirements specified in comments to Section 3/4.8.

SUMMARY OF SONGS 2 TECHNICAL SPECIFICATION OPEN ITEMS CONTINUED

21. Refueling and Fuel Handling Machine Allowable Loads: Allowable loads have been verified and load limit over the spent fuel pool provided as marked.

22. Section 3/4.12 (Radiological Environmental Monitoring): Radiological Assessment Branch comments incorporated.

23. Tc, Pressure and ASI Bases: Provided.

24. Containment Structural Integrity: Resolved as marked.

25. "On" for Filter Heaters (Bases): Accepted.

26. Diesel Generator 2000 hr vs. Full Power Rating (Bases): Resolved per discussion with NRC Licensing Guidance Branch.

27. Section 3/4.12 Bases: Radiological Assessment Branch comments incorporated.

28. Figure 5.1-3 and 5.1-4: Included.

29. + Volume: RCS volume limits are correct as stated.

30. Table 3.3-6 Values: Provided as marked.

31. Table 3.3-9 Values: Provided as marked.

32. Comments on Appendix B Tech Specs: Resolved per cover letter to this enclosure.

33. Process Control Program: Submitted November 6, 1981.

TECHNICAL SPECIFICATION COMMENTS SECTION 2.0

2.2.2 Specifications have been added for changes to the CPC addressible constants.

Table 2.2-1 Notes added for Special Test Exceptions.

B 2.2.1 Clarification added regarding trip and allowable values for seismic-High and Loss of Load Trips.

B 2.2.2 Bases added for CPS addressible constant specification.

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High -		
Four Reactor Coolant Pumps Operating	≤ 110.0% of RATED THERMAL POWER	≤ 111.3% of RATED THERMAL POWER
3. Logarithmic Power Level - High (1) (8)	≤ 0.89% of RATED THERMAL POWER	≤ 0.96% of RATED THERMAL POWER
4. Pressurizer Pressure - High	≤ 2382 psia	≤ 2389 psia
5. Pressurizer Pressure - Low (2)	≥ 1806 psia	≥ 1763 psia
6. Containment Pressure - High	≤ 2.95 psig	≤ 3.14 psig
7. Steam Generator Pressure - Low (3)	≥ 729 psia	≥ 711 psia
8. Steam Generator Level - Low (4)	≥ 23%	≥ 22.23%
9. Local Power Density - High (5)	≤ 21 kw/ft	≤ 21 kw/ft
10. DNBR - Low (5)	≥ 1.19	≥ 1.19
11. Reactor Coolant Flow - Low (6)(9)		
a) DN Rate	≤ 0.3%/sec	≤ 0.315%/sec
b) Floor	≥ 60%	≥ 55%
c) Step	≤ 10%	≤ 13%
12. Steam Generator Level - High (4)	≤ 90%	≤ 90.74%
13. Seismic - High (7)	≤ ~~0.333/0.166~~ 0.48/0.60	≤ ~~0.400/0.200~~ 0.48/0.60
14. Loss of Load	N.A.	N.A.

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

TABLE NOTATION

(1) Trip may be manually bypassed above 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is less than or equal to 10^{-4}% of RATED THERMAL POWER.

(2) Value may be decreased manually, to a minimum value of 300 psia, as pressurizer pressure is reduced, provided the margin between the pressurizer pressure and this value is maintained at less than or equal to 400 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 500 psia. This setpoint may also be manually decreased during the performance of PHYSICS TESTS pursuant to Special Test Exception 3.10.5 and 3.10.6.

(3) Value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached. This setpoint may also be manually decreased during the performance of PHYSICS TESTS pursuant to Special Test Exception 3.10.5 and 3.10.6.

(4) % of the distance between steam generator upper and low level instrument nozzles.

(5) As stored within the Core Protection Calculator (CPC). Calculation of the trip setpoint includes measurement, calculational and processor uncertainties, and dynamic allowances. Trip may be manually bypassed below 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 10^{-4}% of RATED THERMAL POWER.

(6) DN RATE, % of reference value, is the maximum decrease rate of the trip setpoint.

FLOOR, % of reference value, is the minimum value of the trip setpoint.

STEP, % of reference value, is the amount by which the trip setpoint is below the input signal unless limited by DN Rate or Floor. The reference value is that of the input signal at operating flow and coolant temperature.

(7) ~~Zero-period~~ Acceleration, horizontal/vertical, g.

(8) Setpoint may be increased to 5.0% during testing pursuant to Special Test Exception 3.10.6.

(9) Setpoint may be altered to disable trip function during testing pursuant to Special Test Exception 3.10.3 and 3.10.6.

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2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)
CORE PROTECTION CALCULATOR ADDRESSABLE CONSTANTS

2.2.2 Core Protection Calculator Addressable Constants are defined in Table 2.2.2. Type I Addressable Constants are expected to change frequently during plant operation. Type II Addressable Constant values are determined (or confirmed) during PHYSICS TESTS following each fuel loading and are not expected to change during plant operation. Changes to Type I Addressable Constants outside the Allowable Value range require Onsite Review Committee review prior to implementation. Changes to Type II Addressable Constants made other than as a result of post fuel loading PHYSICS TESTS shall require Onsite Review Committee review prior to implementation unless the changes are required for Technical Specification Compliance. Changes to CPC Addressable Constants based on information obtained through the Plant computer - CPC data link shall not be made without prior approval of the Onsite Review Committee.

APPLICABILITY: As shown for Core Protection Calculators in Table 3.3-1.

ACTION: With a Core Protection Calculator Addressable Constant found to be non-conservative, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status.

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TABLE 2.2-2

CORE PROTECTION CALCULATOR ADDRESSABLE CONSTANTS

I. TYPE I ADDRESSABLE CONSTANTS

POINT ID NUMBER	PROGRAM LABEL	DESCRIPTION	ALLOWABLE VALUE
60	FC1	Core coolant mass flow rate calibration constant	$\leq$ 1.15
61	FC2	Core coolant mass flow rate calibration constant	0.0
62	CEANOP	CEAC/RSPT inoperable flag	0, 1, 2, or 3
63	TR	Axiumuthal tilt allowance	$\geq$ 1.02
64	TPC	Thermal power calibration constant	$\geq$0.90
65	KCAL	Neutron flux power calibration constant	$\geq$0.85
66	DNBRPT	DNBR pretrip setpoint	Unrestricted
67	LPDPTS	Local power density pretrip setpoint	Unrestricted

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TABLE 2.2-2 (Continued)

CORE PROTECTION CALCULATOR ADDRESSABLE CONSTANTS

II. TYPE II ADDRESSABLE CONSTANTS

POINT ID NUMBER	PROGRAM LABEL	DESCRIPTION
68	BERR0	Thermal power uncertainty bias
69	BERRI	Power uncertainty factor used in DNBR calculation
70	BERR2	Power uncertainty bias used in DNBR calculation
71	BERR3	Power uncertainty factor used in local power density calculation
72	BERR4	Power uncertainty bias used in local power density calculation
73	EOL	End of life flag
74	ARM1	Multiplier for planar radial peaking factor
75	ARM2	Multiplier for planar radial peaking factor
75	ARM3	Multiplier for planar radial peaking factor
77	ARM4	Multiplier for planar radial peaking factor
78	ARM5	Multiplier for planar radial peaking factor
79	ARM6	Multiplier for planar radial peaking factor
80	ARM7	Multiplier for planar radial peaking factor
81	SC11	Shape annealing correction factor
82	SC12	Shape annealing correction factor
83	SC13	Shape annealing correction factor
84	SC21	Shape annealing correction factor
85	SC22	Shape annealing correction factor
86	SC23	Shape annealing correction factor
87	SC31	Shape annealing correction factor
88	SC32	Shape annealing correction factor

new page

TABLE 2.2-2 (Continued)

CORE PROTECTION CALCULATOR ADDRESSABLE CONSTANTS

II. TYPE II ADDRESSABLE CONSTANTS (Continued)

POINT ID NUMBER	PROGRAM LABEL	DESCRIPTION
89	SC33	Shape annealing correction factor
90	PFMLTD	DNBR penalty factor correction multiplier
91	PFMLTL	LPD penalty factor correction multiplier
92	ASM2	Multiplier for CEA shadowing factor
93	ASM3	Multiplier for CEA shadowing factor
94	ASM4	Multiplier for CEA shadowing factor
95	ASM5	Multiplier for CEA shadowing factor
96	ASM6	Multiplier for CEA shadowing factor
97	ASM7	Multiplier for CEA shadowing factor
98	CORPI	Temperature shadowing correction factor multiplier
99	BPPCC1	Boundary point power correlation coefficient
100	BPPCC2	Boundary point power correlation coefficient
101	BPPCC3	Boundary point power correlation coefficient
102	BPPCC4	Boundary point power correlation coefficient

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2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The Reactor Coolant System components are designed to Section III, 1971 Edition, of the ASME Code for Nuclear Power Plant Components which permits a maximum transient pressure of 110% (2750 psia) of design pressure. The Safety Limit of 2750 psia is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at 3125 psia to demonstrate integrity prior to initial operation.

2.2.1 REACTOR TRIP SETPOINTS

The Reactor Trip Setpoints specified in Table 2.2-1 are the values at which the Reactor Trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

The DNBR - Low and Local Power Density - High are digitally generated trip setpoints based on Limiting Safety System Settings of 1.19 and 21.0 kw/ft, respectively. Since these trips are digitally generated by the Core Protection Calculators, the trip values are not subject to drifts common to trips generated by analog type equipment. The Allowable Values for these trips are therefore the same as the Trip Setpoints. The Seismic - thin a trip is generated by an open-conta signal from a force balance contact device which is likewise not subject to analog-type drifts.

To maintain the margins of safety assumed in the safety analyses, the calculations of the trip variables for the DNBR - Low and Local Power Density - High trips include the measurement, calculational and processor uncertainties and dynamic allowances as defined in CEN-147(S)-P, "Functional Design Specification for a Core Protection Calculator," January, 1981; CEN-139(S)-P, "Functional Design Specification for a Control Element Assembly Calculator," January, 1981; CEN-149(S)-P "CPC-CEAC Data Base Document" and CEN-175(S)-P "SONGS 2 Cycle 1 CPC and CEAC Data Base Document". 9 January 1981, 9 August 1981.

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

No trip setpoint is specified for the Loss of turbine trip since this trip is considered in the load rejection capability of the steam dump system and the turbine stop valve hydraulic actuator pressure switches which actuate the turbine trip equipment protective function does not depend on a specific pressure setpoint.

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BASES

DNBR-Low (Continued)

DNBR after the trip will not result in a violation of the DNBR Safety Limit. CPC uncertainties related to DNBR cover CPC input measurement uncertainties, algorithm modelling uncertainties, and computer equipment processing uncertainties. Dynamic compensation is provided in the CPC calculations for the effects of coolant transport delays, core heat flux delays (relative to changes in core power), sensor time delays, and protection system equipment time delays.

The DNBR algorithm used in the CPC is valid only within the limits indicated below and operation outside of these limits will result in a CPC initiated trip.

a.	RCS Cold Leg Temperature-Low	$\geq$ 495°F
b.	RCS Cold Leg Temperature-High	$\leq$ 580°F
c.	Axial Shape Index-Positive	$\leq$ +0.5
d.	Axial Shape Index-Negative	$\geq$ -0.5
e.	Pressurizer Pressure-Low	$\geq$ 1825 psia
f.	Pressurizer Pressure-High	$\leq$ 2375 psia
g.	Integrated Radial Peaking Factor-Low	$\geq$ 1.28
h.	Integrated Radial Peaking Factor-High	$\leq$ 4.28
i.	Quality Margin-Low	$\geq$ 0

Reactor Coolant Flow - Low

The Reactor Coolant Flow - Low trip provides protection against a reactor coolant pump sheared shaft event and a two pump opposite loop flow coastdown event. A trip is initiated when the pressure differential across the primary side of either steam generator goes below a variable setpoint. This variable setpoint stays a set amount below the pressure differential unless limited by a set maximum decrease rate or a set minimum value. The specified setpoint ensures that a reactor trip occurs to prevent violation of local power density or DNBR safety limits under the stated conditions.

Seismic - High

The Seismic - High trip is provided to trip the reactor in the event of an earthquake which exceeds ~~the operating~~ 60% of the Design basis earthquake level. This trip's setpoint does not correspond to a safety limit and no credit was taken in the accident analyses for operation of this trip.

Loss of Load

The Loss of Load trip is provided to trip the reactor when the turbine is tripped above a predetermined power level. This trip is an equipment protective trip only and is not required for plant safety.

Steam Generator Level-High

The Steam Generator Level-High trip is provided to protect the turbine from excessive moisture carry over. Since the turbine is automatically tripped when the reactor is tripped, this trip provides a reliable means for providing protection to the turbine from excessive moisture carry over. This trip's setpoint does not correspond to a Safety Limit and no credit was taken in the accident analyses for operation of this trip. Its functional capability at the specified trip setting enhances the overall reliability of the Reactor Protection System.

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2.2.2 CPC Addressable Constants

The Core Protection Calculator (CPC) addressable constants are provided to allow calibration of the CPC system to more accurate indications such as calorimetric measurements for power level and RCS flowrate and incore detector signals for axial flux shape, radial peaking factors and CEA deviation penalties. Other CPC addressable constants allow penalization of the calculated DNBR and LPD values based on measurement uncertainties or inoperable equipment. Administrative controls on changes and periodic checking of addressable constant values (see also Technical Specifications 3.3.1 and 6.8.1) ensure that inadvertent misloading is unlikely.

Technical Specification Comments Section 3/4.1

3.1.3.1.f Added information to clarify the definition of Fully Withdrawn.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.4 The Reactor Coolant System lowest operating loop temperature (T_{avg}) shall be greater than or equal to 520°F when the reactor is critical.

APPLICABILITY: MODES 1 and 2#.*

ACTION:

With a Reactor Coolant System operating loop temperature (T_{avg}) less than 520°F, restore T_{avg} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.4 The Reactor Coolant System temperature (T_{avg}) shall be determined to be greater than or equal to 520°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{avg} is less than 535°F.

#With K_{eff} greater than or equal to 1.0.

* See Special test exception 3.10.3, 3.10.5 and 3.10.6

ACTION: (Continued)

d. With one or more full length or part length CEAs misaligned from any other CEAs in its group by more than 7 inches but less than or equal to 19 inches, operation in MODES 1 and 2 may continue, provided that within one hour the misaligned CEA(s) is either:

1. Restored to OPERABLE status within its above specified alignment requirements, or

2. Declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. After declaring the CEA inoperable, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 provided:

a) Within one hour the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on Figure 3.1-2; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation.

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

Otherwise, be in at least HOT STANDBY within 6 hours.

e. With one full length Regulating CEA inoperable due to causes other than addressed by ACTION a., above, and inserted beyond the Long Term Steady State Insertion Limits but within its above specified alignment requirements, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6.

f. With one full length CEA within 2.0 inches of the fully inoperable due to causes other than addressed by ACTION a., above, but within its above specified alignment requirements and either fully withdrawn or within the Long Term Steady State Insertion Limits if in full length CEA group 6, operation in MODES 1 and 2 may continue. Position

g. With one part length CEA inoperable and inserted in the core, operation may continue provided the alignment of the inoperable part length CEA is maintained within 7 inches (indicated position) of all other part length CEAs in its group.

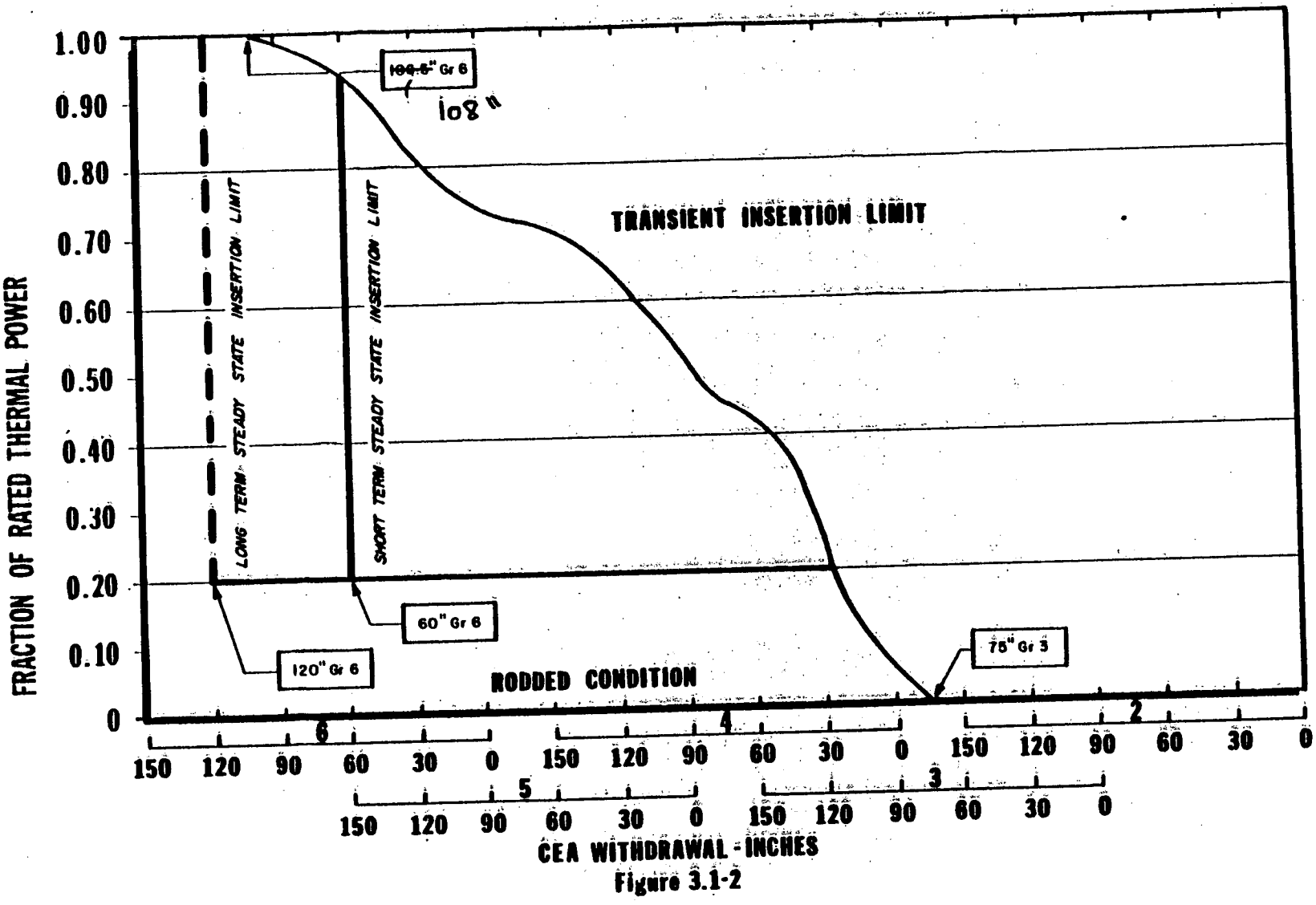
FRACTION OF RATED THERMAL POWER
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0
~~104.5~~" Gr 6
log n
TRANSIENT INSERTION LIMIT
LONG TERM STEADY STATE INSERTION LIMIT
SHORT TERM STEADY STATE INSERTION LIMIT
120" Gr 6
60" Gr 6
75" Gr 3
RODDED CONDITION
6
4
2
5
3
150 120 90 60 30 0 150 120 90 60 30 0 150 120 90 60 30 0
150 120 90 60 30 0 150 120 90 60 30 0
CEA WITHDRAWAL - INCHES

Figure 3.1-2

Technical Specifications Comments Section 3/4.2

4.2.4.4. : Inserted information to clarify the method of determining DNBR Penalty Factor.

3/4.2.6.: Deleted Core Average Coolant Temperature specification and inserted Reactor Coolant Cold Leg Temperature specification IAW the safety analysis

3/4.2.7.: Added a new specification on Axial Shape Index IAW the safety analysis

3/4.2.8.: Added a new specification on Pressurizer Pressure IAW the safety analysis

SURVEILLANCE REQUIREMENTS (Continued)

4.2.4.4 The following DNBR penalty factors shall be verified to be included in the COLSS and CPC DNBR calculations at least once per 31 days:

Burnup $(\frac{GWD}{MTU})$	DNBR Penalty (%)
0-2.4	0.0
2.4-5	3.0
5-10	7.1
10-15	10.3
15-20	12.9
20-25	15.3
25-30	17.4
30-35	19.4
35-40	21.2

INSERT

The penalty for each batch will be determined from the batch's maximum burnup assembly and applied to the batch's maximum radial power peak assembly. A single net penalty for COLSS and CPC will be determined from the penalties associated with each batch accounting for the offsetting margins due to the lower radial power peaks in the higher burnup batches. An alternate method is to determine the penalty for each individual assembly in the core based on that assembly's burnup and apply that penalty to that assembly's radial power peak.

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POWER DISTRIBUTION LIMITS

3/4.2.6 CORE AVERAGE COOLANT TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.2.6 The core average coolant temperature (T_{avg}) shall be less than or equal to 588.05°F.

APPLICABILITY: MODE 1.

ACTION:

With the core average coolant temperature exceeding its limit, restore the temperature to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The core average coolant temperature shall be determined to be within its limit at least once per 12 hours.

NEW PAGE
11/9/81

POWER DISTRIBUTION LIMITS

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.2.6 The Reactor Coolant Cold Leg Temperature (Tc) shall be maintained between 544°F and ~~558~~ 560°F during steady state operation.

APPLICABILITY: MODE 1 above 30% of RATED THERMAL POWER.

ACTION:

With the Reactor Coolant Cold Leg Temperature exceeding its limits, restore the temperature to within its limits within 2 hours or reduce THERMAL POWER to less than 30% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The Reactor Coolant Cold Leg Temperature shall be determined to be within its limits at least once per 12 hours.

NEW PAGE
11/9/81

3/4.2.7 AXIAL SHAPE INDEX

LIMITING CONDITION FOR OPERATION

3.2.7 The core average AXIAL SHAPE INDEX (ASI) shall be maintained within the following limits during steady state operation:

a. COLSS OPERABLE
$-0.28 \leq ASI \leq + 0.50$

b. COLSS OUT OF SERVICE (CPC)
$-0.20 \leq ASI \leq + 0.50$

APPLICABILITY: MODE 1 above 20% of RATED THERMAL POWER*

ACTION:

With the core average AXIAL SHAPE INDEX (AI) exceeding its limits, restore the ASI to within its limits within 2 hours or reduce THERMAL POWER to less than 20% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The core average AXIAL SHAPE INDEX shall be determined to be within its limits at least once per 12 hours using the COLSS or any operable Core Protection Calculator channel.

*See Special Test Exception 3.10.2

New Page
11/3/81

3/4.2.8 PRESSURIZER PRESSURE

LIMITING CONDITION FOR OPERATION

3.2.8 The average pressurizer pressure shall be maintained between 2025 psia and 2275 psia during steady state operation.

APPLICABILITY: MODE 1

ACTION:

With the average pressurizer pressure exceeding its limits, restore the pressure to within its limits within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The average pressurizer pressure shall be determined to be within its limits at least once per 12 hours.

TECHNICAL SPECIFICATION COMMENTS SECTION 3/4.3

3/4.3.1.5: Per SER Supplement 2 Item 7.2.2, additional CPC function testing has been required when CPC temperature is outside the allowed range.

Table 3.3-1: Manual trip and trip breaker quantities/arrangement clarified. Our committment for seismic-high trip operability is prior to exceeding 5% power (in lieu of initial criticality). Additional changes reflect special test exceptions.

Table 3.3-2 and 4.3-1: Safety analysis assumption for RTD response is 6.0 seconds. Seismic-high trip operability per above.

Table 3.3-3: Manual trip quantity/arrangement clarified. CCAS logic clarified (SIAS signal or CCAS trip buttons in lieu of separate process inputs). MSIS action made consistent with fact that MSIS isolates both steam generators although process inputs are provided from each. CPIS process input modes and actions made consistent with shared use as RCS leak detection and effluent monitoring instruments. Also, clarification added that SIAS input to CIAS is at actuated equipment vice CIAS logic level.

Table 3.3-4: Manual trip, CCAS, CIAS, CPIS as per above. Radiation instrument trip values updated/cross-referenced (for effluent monitoring functions). Notes added for special test exceptions.

Table 3.3-5: CCAS and CIAS as per above. SIAS response time for High Pressure Safety Injection revised to reflect small break LOCA assumptions. RAS response times provided.

Table 4.3-2: CCAS, CIAS, CPIS as per above. Master/slave relay testing revised to reflect CE terminology. In particular, testing of subgroup relays is changed from semi-annual (SA) to refueling interval (R) because subgroup relay output cannot be blocked on CE plants; testing during operation would result in challenges to plant safety through actuation of connected components.

Table 3.3-6 and 4.3-2: Updated setpoints provided. Cross-reference to ESFAS requirements provided since there is only one setpoint per instrument, and ESF function is governing. Modes, action and surveillance frequencies revised to be consistent with shared function of instruments. Also, the High Range containment area monitor and condenser evacuation system noble gas monitor are required to be operational by 1/1/82 (in lieu of fuel load). This is acceptable on the basis that a high activity event in containment cannot occur before initial criticality and a release via the condenser air ejector cannot occur before sustained power operation (due to the lack of coolant activity and steam generator tube leakage). Initial criticality will not be achieved until approximately 6 weeks after fuel load.

Technical Specification Comments (continued)

3/4.3.3.3: Revised to preclude unacceptable burden on applicant of frequent shutdown (for earthquakes of considerably less than OBE) merely to calibrate a few seismic instruments located in areas which are inaccessible (due to radiation) during power operation. Calibration and consideration of data from these few instruments at the next cold shutdown is considered sufficient to meet the intent of this specification. Also, the seismic instrument for the Reactor Coolant Pump has been moved to another location on the pump to reduce instrument channel noise due to pump and motor vibration.

Table 3.3-8 and 4.3-5: The 20 meter instrumentation has been deleted from the site (Unit 1) meteorological tower.

Table 3.3-9 and 4.3-6: Panel L042, the Essential Plant Parameter Monitoring System Panel, utilizes hot leg RTD temperature only with range as indicated.

Table 3.3-10: Redundance (for each steam generator) of any one of the two channels of steam generator wide range level to one channel of auxiliary feedwater flowrate has been clarified consistent with our NUREG 0737 committment. It is noted that steam generator level is, in fact, a more positive indication of Reactor Coolant System heat sink.

Table 4.3-8 Notation: SONGS 2/3, liquid effluent monitoring instrument channels will annunciate/isolate on exceeding the setpoint, on circuit failure or on downscale failure. Annunciation/isolation on removal of a channel for service (i.e., not in operating mode) is not a design basis and is, practically, not required due to administrative controls on instrument maintenance. The liquid effluent monitors will not be operational until January 1, 1982. This is considered acceptable due to the lack of reactor coolant activity (and hence, radioactive liquid waste) prior to initial criticality. (Initial criticality will not be achieved until approximately 6 weeks after fuel load.)

Table 3.3-13: Monitors 2/3 RT-7814, 2 RT 7818, 2 RT 7870-1 (which is redundant to 2 RT 7818 insofar as noble gas monitoring and also provides the iodine, particulate and total process flow monitoring for the condenser evacuation system), and the switchable purge stack/vent stack flow rate monitor will not be operational until January 1, 1982. This is considered acceptable based on the following:

a. The waste gas holdup system (gaseous radwaste management system) and condenser evacuation system cannot be release points until buildup of reactor coolant gaseous activity which cannot occur until after initial criticality.

b. Purge and vent stack flow rates will be conservatively calculated from fan running indications and existing plant design data. It is noted that separate flow rate indications are not being provided as this is the NUREG-0737 instrumentation which is switchable between these two locations; the applicants do not consider full-time flow rate indication for each location to be warranted.

SURVEILLANCE REQUIREMENTS (Continued)

2. With 120 volts AC (60 Hz) applied for at least 30 seconds across the input, the reading on the output does not exceed 8 volts DC.

b. For the optical isolators: Verify that the input to output insulation resistance is greater than 10 megohms when tested using a megohmmeter on the 500 volt DC range.

4.3.1.5 The Core Protection Calculator (CPC) System shall be determined OPERABLE at least once per 12 hours by verifying that less than three auto restarts have occurred on each calculator during the past 12 hours. In addition, the CPC cabinet exhaust temperature shall be monitored at least once per 12 hours and the frequency of the CHANNEL FUNCTIONAL TEST of the CPC increased as specified by Table 4.3-1 whenever CPC cabinet exhaust temperature is outside the specified range.

TABLE 3.3-1

REACTOR PROTECTIVE INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2 sets of 2 2 sets of 2	1 set of 2 1 set of 2	2 sets of 2 2 sets of 2	1, 2, 3*, 4*, 5*	1 7A
2. Linear Power Level - High	4	2	3	1, 2	2#, 3#
3. Logarithmic Power Level-High					
a. Startup and Operating	4 4	2(a)(d) 2	3 3	1, 2, 3*, 4*, 5*	2#, 3# 7A
b. Shutdown	4	0	2	3, 4, 5	4
4. Pressurizer Pressure - High	4	2	3	1, 2	2#, 3#
5. Pressurizer Pressure - Low	4	2(b)	3	1, 2	2#, 3#
6. Containment Pressure - High	4	2	3	1, 2	2#, 3#
7. Steam Generator Pressure - Low	4/SG	2/SG	3/SG	1, 2	2#, 3#
8. Steam Generator Level - Low	4/SG	2/SG	3/SG	1, 2	2#, 3#
9. Local Power Density - High	4	2(c)(d)	3	1, 2	2#, 3#
10. DNBR - Low	4	2(c)(d)	3	1, 2	2#, 3#
11. Steam Generator Level - High	4/SG	2/SG	3/SG	1, 2	2#, 3#
12. Reactor Protection System Logic	4	2	3	1, 2, 3*, 4*, 5*	2#, 3# 7A
13. Reactor Trip Breakers	~~2~~ 4	1(f)	~~2~~ 4	1, 2, 3*, 4*, 5*	5 7A
14. Core Protection Calculators	4	2(c)(d)	3	1, 2	2#, 3# and 7
15. CEA Calculators	2	1	2(e)	1, 2	6 and 7
16. Reactor Coolant Flow - Low	4/SG	2/SG	3/SG	1, 2	2#, 3#
@17. Seismic - High	4	2	3	1, 2	2#, 3#
18. Loss of Load	4	2	3	1(g)	2#, 3#

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TABLE 3.3-1 (Continued)

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TABLE NOTATION

*With the protective system trip breakers in the closed position, the CEA drive system capable of CEA withdrawal, and fuel in the reactor vessel.

#The provisions of Specification 3.0.4 are not applicable.

@~~Required~~ To be operational prior to ~~initial criticality.~~ first exceeding 5% of RATED THERMAL POWER

(a) Trip may be manually bypassed above 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is less than or equal to 10^{-4}% of RATED THERMAL POWER.

(b) Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 400 psia.

(c) Trip may be manually bypassed below 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 10^{-4}% of RATED THERMAL POWER. During testing pursuant to Special Test Exception 3.10.3, or 3.10.6 trip may be manually bypassed below 5% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 5% of RATED THERMAL POWER.

(d) Trip may be bypassed during testing pursuant to Special Test Exception 3.10.3.

(e) See Special Test Exception 3.10.2 or 3.10.6.

(f) Each channel shall be comprised of two trip breakers; actual trip logic shall be one-out-of-two taken twice.

(g) Trip may be bypassed below 55% RATED THERMAL POWER.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and/or open the protective system trip breakers.

ACTION 2 - With the number of channels OPERABLE one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may continue provided the inoperable channel is placed in the bypassed or tripped condition within 1 hour. If the inoperable channel is bypassed, the desirability of maintaining this channel in the bypassed condition shall be reviewed in accordance with Specification 6.5.1.6k. The channel shall be returned to OPERABLE status no later than during the next COLD SHUTDOWN.

TABLE 3.3-2 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
11. Steam Generator Level - High	Not Applicable
12. Reactor Protection System Logic	Not Applicable
13. Reactor Trip Breakers	Not Applicable
14. Core Protection Calculators	Not Applicable
15. CEA Calculators	Not Applicable
16. Reactor Coolant Flow-Low	0.9 sec
@17. Seismic-High	Not Applicable
18. Loss of Load	Not Applicable

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

**Response time shall be measured from the output of the sensor. Acceptable CEA sensor response shall be demonstrated by compliance with Specification 3.1.3.4.

#Response time shall be measured from the onset of a 2 out of 4 Reactor Coolant Pump coastdown.

##Response time shall be measured from the output of the sensor. RTD response shall be measured at least once per 18 months by means of the Loop Current Step Response (LCSR) method. The measured T_{RT} of the slowest RTD shall be ~~at least as small as the T_J assumed in the safety analysis~~ less than or equal to 60 seconds.

###Response time shall be measured from the output of the pressure transmitter. The transmitter response time shall be less than or equal to 0.7 seconds where the pressure transmitter response time is equivalent to the time interval required for the transmitter to achieve 63.2% of its total change when subjected to a step change in pressure transmitter pressure.

@Required to be operational prior to initial criticality.

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TABLE 4.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Reactor Trip Breakers	N.A.	N.A.	M	1, 2, 3*, 4*, 5*
14. Core Protection Calculators	S	D(2,4), R(4,5,10)	S(11) M,R(6)	1, 2
15. CEA Calculators	S	R	M,R(6)	1, 2
16. Reactor Coolant Flow-Low	S	R	M	1, 2
@17. Seismic-High	S	R	M	1, 2
18. Loss of Load	S	N.A.	M	1 (9)

TABLE 4.3-1 (Continued)

DRAFT

TABLE NOTATION

* - With reactor trip breakers in the closed position and the CEA drive system capable of CEA withdrawal.

@ - Required to be operational prior to ~~initial criticality~~ first exceeding 5% of RATED THERMAL POWER

(1) - Each startup or when required with the reactor trip breakers closed and the CEA drive system capable of rod withdrawal, if not performed in the previous 7 days.

(2) - Heat balance only (CHANNEL FUNCTIONAL TEST not included), above 15% of RATED THERMAL POWER; adjust the Linear Power Level signals and the CPC addressable constant multipliers to make the CPC delta T power and CPC nuclear power calculations agree with the calorimetric calculation if absolute difference is greater than 2%. During PHYSICS TESTS; these daily calibrations may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(3) - Above 15% of RATED THERMAL POWER, verify that the linear power subchannel gains of the excore detectors are consistent with the values used to establish the shape annealing matrix elements in the Core Protection Calculators.

(4) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) - After each fuel loading and prior to exceeding 70% of RATED THERMAL POWER, the incore detectors shall be used to determine the shape annealing matrix elements and the Core Protection Calculators shall use these elements.

(6) - This CHANNEL FUNCTIONAL TEST shall include the injection of simulated process signals into the channel as close to the sensors as practicable to verify OPERABILITY including alarm and/or trip functions.

(7) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by either using the reactor coolant pump differential pressure instrumentation (conservatively compensated for measurement uncertainties) or by calorimetric calculations (conservatively compensated for measurement uncertainties) and if necessary, adjust the CPC addressable constant flow coefficients such that each CPC indicated flow is less than or equal to the actual flow rate. The flow measurement uncertainty may be included in the BERR1 term in the CPC and is equal to or greater than 4%.

(8) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by calorimetric calculations (conservatively compensated for measurement uncertainties).

(9) - Above 55% of RATED THERMAL POWER.

(10) - Detector plateau curves shall be obtained and evaluated.

(11) - Whenever CPC cabinet exhaust temperature is less than (70)°F or more than (150)°F as monitored per Specification 4.3.1.5.

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TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION	
1. SAFETY INJECTION (SIAS)						
a. Manual (Trip Buttons)	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	8	X
b. Containment Pressure - High	4	2	3	1, 2, 3	9*, 10*	
c. Pressurizer Pressure - Low	4	2	3	1, 2, 3(a)	9*, 10*	
d. Automatic Actuation - Logic	4	2	3	1, 2, 3, 4	9*, 10*	
2. CONTAINMENT SPRAY (CSAS)						
a. Manual (Trip Buttons)	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	8	X
b. Containment Pressure -- High - High	4	2(b)	3	1, 2, 3	9*, 10*	
c. Automatic Actuation Logic	4	2	3	1, 2, 3, 4	9*, 10*	
3. CONTAINMENT ISOLATION (CIAS)						
a. Manual CIAS (Trip Buttons)	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	8	X
b. Manual SIAS (Trip Buttons) (c)	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	8	X
c. Containment Pressure - High	4	2	3	1, 2, 3	9*, 10*	
d. Automatic Actuation Logic	4	2	3	1, 2, 3, 4	9*, 10*	

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. MAIN STEAM LINE ISOLATION					
a. Manual (Trip Buttons)	2/steam generator	1/steam generator	2/operating steam generator	1, 2, 3	~~17~~ 11
b. Steam Generator Pressure - Low	4/steam generator	2/steam generator	3/steam generator	1, 2, 3	9*, 10*
c. Automatic Actuation Logic	4/steam generator	2/steam generator	3/steam generator	1, 2, 3	9*, 10*
5. RECIRCULATION (RAS)					
a. Refueling Water Storage Tank - Low	4	2	3	1, 2, 3	9*, 10*
b. Automatic Actuation Logic	4	2	3	1, 2, 3	9*, 10*
6. CONTAINMENT COOLING (CCAS)					
a. Manual (CCAS Trip Buttons)	2 sets of 2	1 set of 2	2 sets of 2	1, 2, 3, 4	8
~~b. Containment Pressure High~~ b. Manual SIAS (Trip Buttons)	~~2 sets of 2~~ 4	~~1 set of 2~~ 2	~~2 sets of 2~~ 3	1, 2, 3, 4	~~9*, 10*~~ 8
~~c. Pressurizer Pressure - Low~~	~~4~~	~~2~~	~~3~~	~~1, 2, 3(a)~~	~~9*, 10*~~
c. ~~d.~~ Automatic Actuation Logic	4	2	3	1, 2, 3, 4	9*, 10*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. LOSS OF POWER (LOV)					
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	4/Bus	2/Bus	3/Bus	1, 2, 3, 4	9*, 10*
8. EMERGENCY FEEDWATER (EFAS)					
a. Manual (Trip Buttons)	2 sets of 2 per S/G	1 set of 2 per S/G	2 sets of 2 per S/G	1, 2, 3	11
b. Automatic Actuation Logic	4/SG	2/SG	3/SG	1, 2, 3	9*, 10*
c. SG Level ~~and Pressure~~ (A/B) - Low and ΔP (A/B) - High	4/SG	2/SG	3/SG	1, 2, 3	9*, 10*
d. SG Level (A/B) - Low and No S/G Pressure - Low Trip (A/B)	4/SG	2/SG	3/SG	1, 2, 3	9*, 10*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
9. Control Room Isolation (CRIS)					
a. Manual CRIS (Trip Buttons)	2 sets of 2	1	1 sets of 2	All	13*#
b. Manual SIAS (Trip Buttons)	2/unit	1 set of 2	2/unit	1, 2, 3, 4	8
c. Airborne Radiation					
i. Particulate/Iodine	2	1	1	All	13*#
ii. Gaseous	2	1	1	All	13*#
d. Automatic Actuation Logic	1/train	1	1	All	13*#
10. Toxic Gas Isolation (TGIS)					
a. Manual (Trip Buttons)	2	1	1	All	14*#, 15*#
b. Chlorine - High	2	1	1	All	14*#, 15*#
c. Ammonia - High	2	1	1	All	14*#, 15*#
d. Butane/Propane - High	2	1	1	All	14*#, 15*#
e. Carbon Dioxide - High	2	1	1	All	14*#, 15*#
f. Automatic Actuation Logic	1/train	1	1	All	14*#, 15*#

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11. Fuel Handling Isolation (FHIS)					
a. Manual (Trip Buttons)	2	1	1	**	16*#
b. Airborne Radiation					
i. Gaseous	2	1	1	**	16*#
ii. Particulate/Iodine	2	1	1	**	16*#
c. Automatic Actuation Logic	1/train	1	1	**	16*#
12. Containment Purge Isolation (CPIS)					
a. Manual (Trip Buttons)	2	1	1	6	17*#
b. Airborne Radiation					
i. Gaseous	2	1	1	All	17, 17a, 17b
ii. Particulate	2	1	1	All ~~1, 2, 3~~, ~~4, 6~~	17, 17a, 17b
iii. Iodine	2	1	1	All ~~6~~	17, 17b
c. Containment Area Radiation (Gamma)	2	1	1	6	17*#
d. Automatic Actuation Logic	1/train	1	1	All	17, 17a, 17b

PROPOSED REVISED PAGE

TABLE NOTATION

(a) Trip function may be bypassed in this MODE when pressurizer pressure is less than 400 psia; bypass shall be automatically removed when pressurizer pressure is greater than or equal to ~~400~~ 600 psia.

(b) An SIAS signal is first necessary to enable CSAS logic.

(c) Actuated equipment only; does not result in CIAS.

The provisions of Specification 3.0.3 are not applicable.

* The provisions of Specification 3.0.4 are not applicable.

** With irradiated fuel in the storage pool.

ACTION STATEMENTS

ACTION 8 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 9 - With the number of channels OPERABLE one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may continue provided the inoperable channel is placed in the bypassed or tripped condition within 1 hour. If the inoperable channel is bypassed, the desirability of maintaining this channel in the bypassed condition shall be reviewed in accordance with Specification 6.5.1.6k. The channel shall be returned to OPERABLE status no later than during the next COLD SHUTDOWN.

With a channel process measurement circuit that affects multiple functional units inoperable or in test, bypass or trip all associated functional units as listed below.

	Process Measurement Circuit	Functional Unit Bypassed
1.	Containment Pressure - High	Containment Pressure - High (ESF) Containment Pressure - High (RPS)
2.	Steam Generator Pressure - Low	Steam Generator Pressure - Low Steam Generator ΔP 1 and 2 (EFAS)
3.	Steam Generator Level	Steam Generator Level - Low Steam Generator Level - High Steam Generator ΔP (EFAS)

TABLE NOTATION

ACTION 13 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the emergency (except as required by ACTIONS 14, 15) mode of operation.

ACTION 14 - With the number of channels OPERABLE one less than the total number of channels, restore the inoperable channel to OPERABLE status within 7 days or within the next 6 hours initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 15 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 16 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.9.12.

ACTION 17 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.9.9. (Mode 6 only)

ACTION 17a - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.5.1. (Mode 1, 2, 3, 4 only)

ACTION 17b - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.3.3.9. (At all times)

~~ACTION 17c - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated valve inoperable and take the ACTION required by Specification 3.7.1.3~~

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 2.95 psig	≤ 3.14 psig
c. Pressurizer Pressure - Low	≥ 1806 psia (1)	≥ 1763 psia (1)
d. Automatic Actuation Logic	Not Applicable	Not Applicable
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	≤ 16.14 psig	≤ 16.83 psig
c. Automatic Actuation Logic	Not Applicable	Not Applicable
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons) (5)	Not Applicable	Not Applicable
c. Containment Pressure - High	≤ 2.95 psig	≤ 3.14 psig
d. Automatic Actuation Logic	Not Applicable	Not Applicable
4. MAIN STEAM ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	≥ 729 psia (2)	≥ 711 psia (2)
c. Automatic Actuation Logic	Not Applicable	Not Applicable
5. RECIRCULATION (RAS)		
a. Manual RAS (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Storage Tank	18.5% of tap span	19.2~~8~~7% ≥ tap span ≥ 17.7~~4~~3%
c. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-1 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
6. CONTAINMENT COOLING (CCAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. ~~Containment Pressure - High~~ Manual BIAS (Trip Buttons)	~~≤ 2.95 psig~~ Not Applicable	~~≤ 3.14 psig~~ Not Applicable
~~c. Pressurizer Pressure - Low~~	~~≥ 1806 psia~~	~~≥ 1763 psia~~
c. ~~d.~~ Automatic Actuation Logic	Not Applicable	Not Applicable
7. LOSS OF POWER (LOV)		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	See Fig. 3.3-1 (4)	See Fig. 3.3-1 (4)
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level-Low	≥ 23% (3)	≥ 22.23% (3)
c. Steam Generator ΔP-High (SG-A > SG-B)	≤ 50 psi	≤ 66.25 psi
d. Steam Generator ΔP-High (SG-B > SG-A)	≤ 50 psi	≤ 66.25 psi
e. Steam Generator (A&B) Pressure - Low	≥ 729 psia (2)	≥ 711 psia (2)
f. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
9. Control Room Isolation (CRIS)		
a. Manual CRIS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Airborn Radiation		
i. Particulate/Iodine	~~$\leq 6.4 \times 10^1$~~ 5.7×10^4 cpm	~~$\leq 6.7 \times 10^1$~~ 6.0×10^4 cpm
ii. Gaseous	~~$\leq 8.8 \times 10^4$~~ 3.8×10^1 cpm	~~$\leq 9.3 \times 10^4$~~ 4.0×10^1 cpm
d. Automatic Actuation Logic	Not Applicable	Not Applicable
10. Toxic Gas Isolation (TGIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Chlorine - High	$\leq$ 4.1 ppm	$\leq$ 4.3 ppm
c. Ammonia - High	$\leq$ 42.4 ppm	$\leq$ 44.7 ppm
d. Butane/Propane - High	$\leq$ 84.8 ppm	$\leq$ 89.3 ppm
e. Carbon Dioxide - High	$\leq$ 4061.3 ppm	$\leq$ 4275.0 ppm
f. Automatic Actuation Logic	Not Applicable	Not Applicable

X

X

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
11. Fuel Handling Isolation (FHIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Airborne Radiation		
i. Gaseous	~~$\leq 6.4 \times 10^{1}$~~ 1.3×10^{2} cpm	~~$\leq 6.7 \times 10^{1}$~~ 1.4×10^{2} cpm
ii. Particulate/Iodine	~~$\leq 7.3 \times 10^{1}$~~ 5.7×10^{4} cpm	~~$\leq 7.7 \times 10^{1}$~~ 6.0×10^{4} cpm
c. Automatic Actuation Logic	Not Applicable	Not Applicable
12. Containment Purge Isolation (CPIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Airborne Radiation		
i. Gaseous	$\leq$ per ODCM	$\leq$ per ODCM
ii. Particulate	~~$\leq 1.5 \times 10^{8}$ cpm~~ per ODCM	~~$\leq 1.6 \times 10^{8}$ cpm~~ per ODCM
iii. Iodine	~~$\leq 1.3 \times 10^{9}$ cpm~~ per ODCM	~~$\leq 1.4 \times 10^{9}$ cpm~~ per ODCM
c. Containment Area Radiation (Gamma)	~~$\leq$ (later)~~ 2.4 mr/hr	$\leq$ 2.5 mr/hr
d. Automatic Actuation Logic	Not Applicable	Not Applicable

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TABLE 3.3-4 (Continued)

TABLE NOTATION

(1) Value may be decreased manually, to a minimum of greater than or equal to 300 psia, as pressurizer pressure is reduced, provided the margin between the pressurizer and this value is maintained at less than or equal to 400 psia;* the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer is greater than or equal to ~~400~~ 500 psia. This setpoint may also be decreased during the performance of testing pursuant to special test Exception 3.10.5 and 3.10.6. X X

(2) Value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi;* the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached. This setpoint may also be decreased during the performance of testing pursuant to special test Exception 3.10.5 and 3.10.6. X X

(3) % of the distance between steam generator upper and lower level instrument nozzles.

(4) Inverse time relay set value 3165V, trip will occur within the tolerances specified in Figure 3.3-1 for the range of bus voltages.

(5) Actuated equipment only; does not result in CIAS. X

*Variable setpoints are for use only during normal, controlled plant heatups and cooldowns.

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TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME (SEC)
1. Manual	
a. SIAS	
Safety Injection	Not Applicable
Control Room Isolation	Not Applicable
Containment Isolation (3)	Not Applicable
b. CSAS Containment Emergency Cooling	Not Applicable
Containment Spray	Not Applicable
c. CIAS	
Containment Isolation	Not Applicable
d. MSIS	
Main Steam Isolation	Not Applicable
e. RAS	
Containment Sump Recirculation	Not Applicable
f. CCAS	
Containment Emergency Cooling	Not Applicable
g. EFAS	
Auxiliary Feedwater	Not Applicable
h. CRIS	
Control Room Isolation	Not Applicable
i. TGIS	
Toxic Gas Isolation	Not Applicable
j. FHIS	
Fuel Handling Building Isolation	Not Applicable
k. CPIS	
Containment Purge Isolation	Not Applicable

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INITIATING SIGNAL AND FUNCTION	RESPONSE TIME (SEC)
2. Pressurizer Pressure-Low	
a. SIAS	
(1) Safety Injection	
(a) High Pressure Safety Injection	~~31.2*~~ ~~41.2*~~
(b) Low Pressure Safety Injection	41.2*
(2) Control Room Isolation	Not Applicable
(3) Containment Isolation (NOTE 3)	11.2* (NOTE 2)
(4) Containment Spray (Pumps)	25.6*
(5) Containment Emergency Cooling	
(a) CCW ~~Pumps~~ Pumps	31.2*
(b) CCW Valves (Note 4)	11.2* ~~(NOTE 4)~~
(c) Emergency Cooling Fans	21.2*
~~b. CCAS~~	
~~(1) Containment Emergency Cooling~~	~~21.2*~~
3. Containment Pressure-High	
a. SIAS	
(1) Safety Injection	
(a) High Pressure Safety Injection	41.0*
(b) Low Pressure Safety Injection	41.0*
(2) Control Room Isolation	Not Applicable
(3) Containment Spray (Pumps)	25.4*
(4) Containment Emergency Cooling	
(a) CCW Pumps	31.0*
(b) CCW Valves	11.0 (NOTE 4)
(c) Emergency Cooling Fans	21.0*
b. CIAS	
(1) Containment Isolation	10.9* (NOTE 2)
~~c. CCAS~~	
~~(1) Containment Emergency Cooling~~	~~21.0*~~
4. Containment Pressure - High-High	
a. CSAS	
(1) Containment Spray	21.0*

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Table 3.3-5 (Continued)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME (SEC)
5. Steam Generator Pressure - Low	
a. MSIS	
(1) Main Steam Isolation (MSIV)	5.9
(2) Main Feedwater Isolation	10.9
6. Refueling Water Storage Tank - Low	
a. RAS	
(1) Containment Sump Valves Open	~~(later)~~ 45.7* x
(2) ECCS Miniflow Valves Shut	~~(later)~~ 40.7* x
7. 4.16 kv Emergency Bus Undervoltage	
a. LOV (loss of voltage and degraded voltage)	Figure 3.3-1
8. Steam Generator Level - Low (and No Pressure-Low Trip)	
a. EFAS	
(1) Auxiliary Feedwater (AC trains)	40.9*
(2) Auxiliary Feedwater (steam/DC train)	30.9
9. Steam Generator Level - Low (and ΔP - High)	
a. EFAS	
(1) Auxiliary Feedwater (AC trains)	40.9*
(2) Auxiliary Feedwater (Steam/DC train)	30.9
10. Control Room Ventilation Airborne Radiation	
a. CRIS	
(1) Control Room Ventilation - Emergency Mode	Not Applicable
11. Control Room Toxic Gas (Chlorine)	
a. TGIS	
(1) Control Room Ventilation - Isolation Mode	16 (NOTE 5) |
12. Control Room Toxic Gas (Ammonia)	
a. TGIS	
(1) Control Room Ventilation - Isolation Mode	36 (NOTE 5) |

TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTAION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Pressurizer Pressure - Low	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3, 4
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Pressure -- High - High	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3, 4
3. CONTAINMENT ISOLATION (CIAS)				
a. Manual CIAS (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Manual SIAS (Trip Buttons)(5)	N.A.	N.A.	R	1, 2, 3, 4
c. Containment Pressure - High	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3, 4
4. MAIN STEAM ISOLATION (MSIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3
b. Steam Generator Pressure - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3
5. RECIRCULATION (RAS)				
a. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3
b. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3
6. CONTAINMENT COOLING (CCAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
~~b. Containment Pressure - High~~	~~S~~ N.A.	~~R~~ N.A.	~~M~~ R	1, 2, 3, 4
~~c. Pressurizer Pressure - Low~~	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~ R(4)	1, 2, 3, 4

Manual SIAS (Trip Buttons)

TABLE 4.3.-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
7. LOSS OF POWER (LOV)				
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	S	R	R	1, 2, 3, 4
8. EMERGENCY FEEDWATER (EFAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3
b. SG Level and Pressure (A/B)-Low and ΔP (A/B) - High	S	R	M	1, 2, 3
c. SG Level (A/B) - Low and No Pressure - Low Trip (A/B)	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~R(4)	1, 2, 3
9. Control Room Isolation (CRIS)				
a. Manual CRIS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
c. Airborne Radiation				
i. Particulate/Iodine	S	R	M	All
ii. Gaseous	S	R	M	All
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), ~~SA~~R(4)	All
10. Toxic Gas Isolation (TGIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Chlorine - High	S	R	M	All
c. Ammonia - High	S	R	M	All
d. Butane/Propane - High	S	R	M	All
e. Carbon Dioxide - High	S	R	M	All
f. Automatic Actuation Logic	N.A.	N.A.	~~M(1)(3), SA(4)~~ R(3)	All

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TABLE 4.3.-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED	
11. Fuel Handling Isolation (FHIS)					
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.	
b. Airborne Radiation					
i. Gaseous	S	R	M	*	
ii. Particulate/Iodine	S	R	M	*	
c. Automatic Actuation Logic	N.A.	N.A.	R(3) ~~(4)~~	*	X
12. Containment Purge Isolation (CPIS)					
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.	
b. Airborne Radiation					
i. Gaseous	(2)	(2)	(2)	All	
ii. Particulate	~~S~~ (2)	~~R~~ (2)	~~M~~ (2)	All ~~1, 2, 3, 4, 6~~	X
iii. Iodine	~~S~~ (2)	~~R~~ (2)	~~M~~ (2)	All ~~6~~	X
c. Containment Area Radiation (Gamma)	S	R	M	6	
d. Automatic Actuation Logic	N.A.	N.A.	~~(2)(3), 5(4)~~ R(3)	All	X

TABLE NOTATION

(1) Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(2) In accordance with Table 4.3-9 surveillance requirements for these instrument channels.

(3) Testing of Automatic Actuation Logic shall include energization/de-energization of each ~~master~~ initiation relay and verification of the OPERABILITY of each ~~master~~ relay. X

(4) A ~~slave~~ subgroup relay test shall be performed which shall include the energization/de-energization of each ~~slave~~ initiation relay and verification of the OPERABILITY of each ~~slave~~ subgroup relay. X

(5) Actuated equipment only; does not result in CIAS.

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TABLE 3.3-6

RADIATION MONITORING ALARM INSTRUMENTATION

	INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM SETPOINT	MEASUREMENT RANGE	ACTION
1.	Area Monitors					
**	a. Containment - High Range	2	1, 2, 3	2 ~~(later)~~ R/hr	1-10^8 R/hr	18
			4	10 ~~(later)~~ R/hr		19
	b. Containment - Purge Isolation	1	1, 2, 3, 4	≤ ~~670 MR/hr~~ 32.5 mr/hr	10^{-1}-10^5 mr/hr	19 (a)
			6	# ~~≤ 2.5 MR/hr~~		(a)
**	c. Main Steam Line	1/line	1, 2, 3	1mr/hr (lo); 1R/hr (hi)	10^1-10^4 mr/hr; 10^1-10^4 R/hr	
				~~(later) R/hr~~	~~1-10^3 R/hr~~	18
			4	~~(later) R/hr~~		19
				1mr/hr (lo); 1R/hr (hi)		
2.	Process Monitors					
	a. Fuel Storage Pool Airborne					
	i. Gaseous	1	*	# ~~≤ 2 x background~~	10^1 -10^7 cpm	~~(b)~~ (d)
	ii. Particulate/Iodine	1	*	# ~~≤ 2 x background~~	10^1 -10^7 cpm	~~(b)~~ (d)
	b. Containment Airborne					
	i. Gaseous	1	~~1, 2, 3, 4, 6~~ All	Per ODCM	10^1 -10^7 cpm	(a),(b),(c)
	ii. Particulate	1	~~1, 2, 3, 4~~	~~NOT APPLICABLE~~ Per ODCM		~~(b)~~
			~~6~~ All	~~≤ 2 x background~~	10^1 -10^7 cpm	(a),(b),(c)
	iii. Iodine	1	~~1, 2, 3, 4~~	~~NOT APPLICABLE~~		~~(b)~~
			~~6~~ All	~~≤ 2 x background~~ Per ODCM	10^1 -10^7 cpm	(a),(c)
	c. Control Room Airborne					
	i. Particulate/Iodine	1	All	# ~~≤ 2 x background~~	10^1 -10^7 cpm	~~(c)~~ (e)
	ii. Gaseous	1	All	# ~~≤ 2 x background~~	10^1 -10^7 cpm	~~(c)~~ (e)

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TABLE 3.3-6 (Continued)

RADIATION MONITORING ALARM INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM SETPOINT	MEASUREMENT RANGE	ACTION	
3. Noble Gas Monitors						
a. Plant Vent Stack	1	All	Per ODCM	~~$40 - 4 \times 10^6$~~ $10^1 - 10^7$ cpm	19(c)	X
** b. Condenser ~~Exhaust~~ Evacuation System	1	~~1, 2, 3, 4~~ All	Per ODCM	~~$40 - 4 \times 10^6$~~ $10^1 - 10^7$ cpm	19(c)	X

TABLE 3.3-6 (Continued)

ACTION STATEMENTS

ACTION 18 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.3.3.6.

ACTION 19 - With the number of OPERABLE Channels less than the Minimum Channels OPERABLE requirement, restore the inoperable Channel(s) to OPERABLE status within 7 days, or be in at least HOT STANDBY within the next 6 hours, and in at least HOT SHUTDOWN within the following 6 hours and in COLD SHUTDOWN within the subsequent 24 hours.

In accordance with Engineered Safety Feature trip value specified by Table 3.3-4

*With irradiated fuel in the storage pool.

**NUREG-0737 item to be operational by 1 January 1982.

(a) In accordance with Table 3.3-3 - ACTION 17.

(b) In accordance with Table 3.3-3 - ACTION 17a.

(c) In accordance with Table 3.3-3 - ACTION 17b.

(d) In accordance with Table 3.3-3 - ACTION 16.

(e) In accordance with Table 3.3-3 - ACTION 13.

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1.	Area Monitors				
**	a. Containment - High Range	S	R	M	1, 2, 3, 4
	b. Containment - Purpose Isolation	# S #	# R #	# M #	1, 2, 3, 4, ~~6~~ 6
**	c. Main Steam Line	S	R	M	1, 2, 3, 4
2.	Process Monitors				
	a. Fuel Storage Pool Airborne				
	i. Gaseous	#	#	#	*
	ii. Particulate/Iodine	#	#	#	*
	b. Containment Airborne				
	i. Gaseous	@	@	@	All
	ii. Particulate	# @	# @	# @	~~1, 2, 3, 4, 6~~ All
	iii. Iodine	# @	# @	# @	~~1, 2, 3, 4, 6~~ All
	c. Control Room Airborne				
	i. Particulate	#	#	#	All
	ii. Gaseous	#	#	#	All

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
PROCESS MONITORS (Continued)				
3. Noble Gas Monitors				
a. Plant Vent Stack	@	@	@	All
b. Condenser ~~Exhaust~~ Evacuation System	@	@	@	~~1, 2, 3, 4~~ All

NOTES:

#In accordance with Table 4.3-2 surveillance requirements for these instrument channels.

*With irradiated fuel in the storage pool.

**NUREG 0737 item to be operational by January 1, 1982.

@In accordance with Table 4.3-9 surveillance requirements for these instrument channels.

INSTRUMENTATION

SEISMIC INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.3 The seismic monitoring instrumentation shown in Table 3.3-7 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more seismic monitoring instruments inoperable for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrument(s) to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.3.1 Each of the above seismic monitoring instruments shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3-4.

which is accessible during power operation and whic

4.3.3.3.2 Each of the above seismic monitoring instruments actuated during a seismic event (greater than or equal to 0.02 g) shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency spectrum and resultant effect upon facility features important to safety. Each of the above seismic monitoring instruments which is actuated during a seismic event (greater than or equal to 0.02g) but is not accessible during power operation shall be restored to OPERABLE status and a CHANNEL CALIBRATION performed at the next cold shutdown. A supplemental report shall be prepared and submitted to the Commission within 10 days pursuant to Specification 6.9.2 describing the additional data from these instruments.

the accessible

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TABLE 3.3-7

SEISMIC MONITORING INSTRUMENTATION

Instruments & Sensor Locations	Measurement Range	Minimum Instrument Operable
1. Triaxial Time-History Strong Motion Accelerometers		
a. Steam Generator Base Support	-2 to +2g	1
b. Pressurizer Base Support	-2 to +2g	1
c. ~~Top of~~ Reactor Coolant Pump ~~Motor~~	-2 to +2g	1
d. Containment Base in Tendon Gallery	-2 to +2g	1
e. Containment Operating Level	-2 to +2g	1
f. Unit #1 Free Field	-1 to +1g	1
g. Control Building Basement	-2 to +2g	1
h. Control Building Roof	-2 to +2g	1
i. Safety Equipment Building Base Slab	-2 to +2g	1
j. Safety Equipment Building Piping Support	-2 to +2g	1
k. Radwaste Building Equipment Support	-2 to +2g	1
2. Triaxial Peak Reading Accelerographs		
a. Control Building-Control Room	-2 to +2g	1
b. Control Building Base	-2 to +2g	1
c. Top of Containment Structure	-5 to +5g	1
d. Reactor Coolant Piping	-2 to +2g	1
3. Seismic Triggers		
a. Containment Base in Tendon Gallery	+0.005 to +0.05g	1
b. Containment Operating Level	+0.005 to +0.05g	1
4. Seismic Switches		
a. Steam Generator Base Support	Set pt. 0.45 Horz/0.30 Vert.	1**
b. Containment Base in Tendon Gallery	Set pt. 0.40 Horz/0.50 Vert.	1**
5. Seismic Alarm Annunciator (4a & 4b are sensors)		
a. Control Room Panel L-167		
6. Peak Shock Recorder		
a. Containment Base in Tendon Gallery	2 to 25.4 Hz 1.6 to 90g	1**
7. Peak Shock Annunciator	2 to 25.4 Hz 1.6 to 90g	1
a. Control Room Panel L-167		

** With control room indication

TABLE 4.3-4

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	FUNCTIONAL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Triaxial Time-History Strong Motion Accelerometers			
a. Steam Generator Base Support	M*	R	SA
b. Pressurizer Base Support	M*	R	SA
c. ~~Top of~~ Reactor Coolant Pump ~~Motor~~	M*	R	SA
d. Containment Base in Tendon Gallery	M*	R	SA
e. Containment Operating Level	M*	R	SA
f. Unit #1 Free Field	M*	R	SA
g. Control Building Basement	M*	R	SA
h. Control Building Roof	M*	R	SA
i. Safety Equipment Building Base	M*	R	SA
j. Safety Equipment Building Piping Support	M*	R	SA
k. Radwaste Building Equipment Support	M*	R	SA
2. Triaxial Peak Recording Accelerographs			
a. Control Building-Control Room	N/A	R	N/A
b. Control Building Base	N/A	R	N/A
c. Top of Containment Structure	N/A	R	N/A
d. Reactor Coolant Piping	N/A	R	N/A
3. Seismic Triggers			
a. Containment Base in Tendon Gallery	M	R	SA
b. Containment Operating Level	M	R	SA
4. Seismic Switches			
a. Steam Generator Base Support	M	R**	SA**
b. Containment Base in Tendon Gallery	M	R**	SA**
5. Seismic Alarm Annunciators (4a & 4b are sensors)			
a. Control Room Panel L-167	M	R	SA
6. Peak Shock Recorder			
a. Containment Base in Tendon Gallery	N/A	R**	N/A
7. Peak Shock Annunciator			
a. Control Room Panel L-167	N/A	R**	N/A

(* Except seismic trigger)
(**With Control Room indication)

TABLE 3.3-8

METEOROLOGICAL MONITORING INSTRUMENTATION

INSTRUMENT	LOCATION	MINIMUM OPERABLE
1. WIND SPEED		
a. 0-50 mph	Nominal Elev. 10 meters	1
~~b. 0-50 mph~~	~~Nominal Elev. 20 meters~~	~~1~~
b. c. 0-50 mph	Nominal Elev. 40 meters	1
2. WIND DIRECTION		
a. 0-360-180°	Nominal Elev. 10 meters	1
~~b. 0-360-180°~~	~~Nominal Elev. 20 meters~~	~~1~~
b. c. 0-360-180°	Nominal Elev. 40 meters	1
3. AIR TEMPERATURE		
a. -30 to +50°C	Nominal Elev. 10 meters	1
4. Delta Temperature		
a. -3°C to +3°C	Nominal Elev. 10/40 meters	1
b. -3°C to +3°C	Nominal Elev. 10/40 meters	1
5. Sigma Azimuth		
a. -0 to 45°	Nominal Elev. 10 meters	1

TABLE 4.3-5

METEOROLOGICAL MONITORING INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. WIND SPEED		
a. Nominal Elev. 10 meters	D	SA
~~b. Nominal Elev. 20 meters~~	~~D~~	~~SA~~
b. Nominal Elev. 40 meters	D	SA
2. WIND DIRECTION		
a. Nominal Elev. 10 meters	D	SA
~~b. Nominal Elev. 20 meters~~	~~D~~	~~SA~~
b. Nominal Elev. 40 meters	D	SA
3. AIR TEMPERATURE		
a. Nominal Elev. 10 meters	D	SA
4. Delta Temperature		
a. Nominal Elev. 10/40 meters	D	SA
b. Nominal Elev. 10/40 meters	D	SA
5. Sigma Azimuth		
a. Nominal Elev. 10 meters	D	SA

SAN ONOFRE-UNIT 2

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

	INSTRUMENT	READOUT LOCATION	CHANNEL RANGE	MINIMUM CHANNELS OPERABLE
1.	Log Power Level	*	10^{-8} - 200%	1
2.	Reactor Coolant Cold Leg Temperature	*	0-600°F	1/loop
3.	Pressurizer Pressure	*	0-3000 psia	1
4.	Pressurizer Level	*	0-100%	1
5.	Steam Generator Pressure	*	0-1200 psia	1/steam generator
6.	Steam Generator Level	*	0-100%	1/steam generator
7.	Reactor Coolant Boron Concentration	*	0-2500 ppm	1
8.	Condenser Vacuum	*	0-5" Hg	1
9.	Volume Control Tank Level	*	0-100%	1
10.	Letdown Heat Exchanger Pressure	*	0-600 psig	1
11.	Letdown Heat Exchanger Temperature	*	0-200°F	1
12.	Boric Acid Makeup Tank Level	*	0-100%	1
13.	Condensate Storage Tank Level	*	0-100%	1
14.	Reactor Coolant Hot Leg Temperature	#	~~(later)~~ 190 - 625°F	1
~~15.~~	~~Reactor Coolant Cold Leg Temperature~~	#	~~(later)~~	~~1~~
15. ~~16.~~	Pressurizer Pressure - Low Range	#	0-1600 psia	1
16. ~~17.~~	Pressurizer Pressure - High Range	#	1500-2500 psia	1
17 ~~18.~~	Pressurizer Level	#	0-100%	1
18. ~~19.~~	Steam Generator Pressure	#	0-1050 psia	1/steam generator
19. ~~20.~~	Steam Generator Level	#	0-100%	1/steam generator

*Panel L042
#Panel L411

THIS PAGE OPEN PENDING RECEIPT OF INFORMATION FROM THE APPLICANT

PAGE 3.3-39 AMD. 19 JUN 1981

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1.	Log Power Level	M	R
2.	Reactor Coolant Cold Leg Temperature	M	R
3.	Pressurizer Pressure	M	R
4.	Pressurizer Level	M	R
5.	Steam Generator Level	M	R
6.	Steam Generator Pressure	M	R
7.	Reactor Coolant Boron Concentration	M	R
8.	Condenser Vacuum	M	R
9.	Volume Control Tank Level	M	R
10.	Letdown Heat Exchanger Pressure	M	R
11.	Letdown Heat Exchanger Temperature	M	R
12.	Boric Acid Makeup Tank Level	M	R
13.	Condensate Storage Tank Level	M	R
14.	Reactor Coolant Hot Leg Temperature	M	R
~~15.~~	~~Reactor Coolant Cold Leg Temperature~~	~~M~~	~~R~~
15. ~~16.~~	Pressurizer Pressure - Low Range	M	R
16. ~~17.~~	Pressurizer Pressure - High Range	M	R
17. ~~18.~~	Pressurizer Level	M	R
18. ~~19.~~	Steam Generator Pressure	M	R
19. ~~20.~~	Steam Generator Level	M	R

TABLE 3.3-10

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE
1. Containment Pressure - Narrow Range	2	1
2. Containment Pressure - Wide Range	2	1
3. Reactor Coolant Outlet Temperature - T_{Hot} (Wide Range)	2	1
4. Reactor Coolant Inlet Temperature - T_{Cold} (Wide Range)	2	1
5. Pressurizer Pressure - Wide Range	2	1
6. Pressurizer Water Level	2	1
7. Steam Line Pressure	2/steam generator	1/steam generator
8. Steam Generator Water Level - Narrow Range	1/steam generator	1/steam generator
9. Steam Generator Water Level - Wide Range	2/steam generator	~~1/steam generator~~ #
10. Refueling Water Storage Tank Water Level	2	1
11. Auxiliary Feedwater Flow Rate	1/steam generator	~~1/steam generator~~ *
12. Reactor Coolant System Subcooling Margin Monitor	2	1
13. Safety Valve Position Indicator	2/valve	1/valve
14. Spray System Temperature	2	1
15. Spray System Pressure	2	1
16. LPSI Header Temperature	2	1
17. Containment Temperature	2	1
18. Containment Water Level - Narrow Range	2	1
19. Containment Water Level - Wide Range	2	1
20. Core Exit Thermocouples	7/core quadrant	4/core quadrant

TABLE 3.3-10

ACCIDENT MONITORING INSTRUMENTATION (CONTINUED)

	INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE
**21.	Containment Area Radiation - High Range	2	1
**22.	Main Steam Line Area Radiation	1/steam ~~generator~~ line	1/steam ~~generator~~ line
** 23.	Condenser ~~Air Ejector Noble Gas~~ Evacuation System Radiation Monitor - Wide Range	1	1
** 24.	Purge/Vent Stack ~~Noble Gas~~ Radiation Monitor - Wide Range	1/~~stack~~	1/~~stack~~
25.	Cold Leg HPSI Flow	2/cold leg	1/cold leg
26.	Hot Leg HPSI Flow	1/hot leg	1/hot leg

NOTES:

** NUREG 0737 item to be operational by January 1, 1982.

Per steam generator: either 2 steam generator wide range level channels or 1 steam generator wide range level channel plus 1 auxiliary feedwater flowrate channel.

TABLE 4.3-7

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS (CONTINUED)

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
**21. Containment Area Radiation - High Range	(a)	(a)
**22. Main Steam Line Area Radiation	(a)	(a)
**23. Condenser ~~Air Ejector Noble Gas~~ Evacuation System Radiation Monitor - Wide Range	M	R
**24. Purge/Vent Stack ~~Noble Gas~~ Radiation Monitor - Wide Range	M	R
25. Cold Leg HPSI Flow	M	R
26. Hot Leg HPSI Flow	M	R

NOTES:

(a) In accordance with Table 4.3-3.

** NUREG 0737 item to be operational by January 1, 1982.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

	INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1.	GROSS RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE		
	a. Liquid Radwaste Effluent Line - 2/3 RT - 7813 **	1	28
	b. Steam Generator Blowdown (Neutralization Sump) ** Effluent Line - 2RT - 7817	1	29
	c. Turbine Building Sumps Effluent Line - 2RT - 7821 **	1	30
2.	FLOW RATE MEASUREMENT DEVICES		
	a. Liquid Radwaste Effluent Line	1	31
	b. Steam Generator Blowdown (Neutralization Sump) Effluent Line	1	31

** To be operational by January 1, 1981.

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TABLE 4.3-8

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. GROSS BETA OR GAMMA RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE				
a. Liquid Radwaste Effluents Line - 2/3 RT - 7817 **	D	P	R(2)	Q(1)
b. Steam Generator Blowdown (Neutralization Sump) Effluent Line - 2RT - 7817	D	M	R(2)	Q(1)
c. Turbine Building Sumps Effluent Line - 2RT - 7821	D	M	R(2)	Q(1)
2. FLOW RATE MEASUREMENT DEVICES				
a. Liquid Radwaste Effluent Line	D(3)	N.A.	R	Q
b. Steam Generator Blowdown (Neutralization Sump) Effluent Line	D(3)	N.A.	R	Q

** To be operational by January 1, 1981

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TABLE 4.3-8 (Continued)

TABLE NOTATION

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. ~~Instrument controls not set in operate mode.~~ X

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the intial calibration shall be used. X

(3) CHANNEL CHECK shall consist of verifying indication of flow during periods of release. CHANNEL CHECK shall be made at least once per 24 hours on days on which continuous, periodic, or batch releases are made.

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TABLE 3.3-13

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

	INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1.	WASTE GAS HOLDUP SYSTEM			
	a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release - 2/3 RT - 7814 ***	1	*	35
	b. Effluent System Flow Rate Measuring Device	1	*	36
2.	WASTE GAS HOLDUP SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
	a. Hydrogen Monitor	2	**	39
	b. Oxygen Monitor	2	**	39
3.	CONDENSER EVACUATION SYSTEM			
	a. Noble Gas Activity Monitor - 2RT - 7818 or 2RT-7870-1 ***	1	*	37, (a)
	b. Iodine Sampler***	1	*	~~41~~ 40
	c. Particulate Sampler***	1	*	~~41~~ 40
	d. Flow Rate Monitor***	1	*	36
4.	PLANT VENT STACK			
	a. Noble Gas Activity Monitor (Providing Alarm and Automatic Termination of Release from Waste Gas Storage Tanks) - 2/3 RT - 7808	1	*	37, (a)
	b. Iodine Sampler	1	*	~~39~~ 40
	c. Particulate Sampler	1	*	~~39~~ 40
	d. Flow Rate Monitor***	1	*	36
	e. Sampler Flow Rate Measuring Device***	1	*	36
5.	CONTAINMENT PURGE SYSTEM			
	a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release - 2RT - 7804-1 or 2RT - 7807-2	1	*	38, (b), (c)
	b. Iodine Sampler	1	*	~~41~~ 40, (c)
	c. Particulate Sampler	1	*	40, (b), (c)
	d. Flow Rate Monitor***	1	*	36
	e. Sampler Flow Rate Measuring Device***	1	*	36

TABLE 4.3-9

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. WASTE GAS HOLDUP SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release - 2/3 RT - 7814 ~~***~~	P	P	R(3)	Q(1)	*
b. Flow Rate Monitor	P	N.A.	R	Q	*
2. WASTE GAS HOLDUP SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor (continuous)	D	N.A.	Q(4)	M	**
b. Hydrogen Monitor (periodic)	D	N.A.	Q(4)	M	**
c. Oxygen Monitor (continuous)	D	N.A.	Q(5)	M	**
d. Oxygen Monitor (periodic)	D	N.A.	Q(5)	M	**
3. CONDENSER EVACUATION SYSTEM					
a. Noble Gas Activity Monitor - 2 RT - 7818 or ~~2RT-7810-1~~ ~~***~~	D	M	R(3)	Q(2)	*
b. Iodine Sampler***	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler***	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor***	D	N.A.	R	Q	*
4. PLANT VENT STACK					
a. Noble Gas Activity Monitor - 2/3 RT - 7808	D	M	R(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor***	D	N.A.	R	Q	*
e. Sampler Flow Rate Measuring Device	D	N.A.	R	Q	*

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TABLE 4.3-9 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
5. CONTAINMENT PURGE SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release - 2/3 RT - 7804-1 or 2RT - 7807-2	S	P(6)	R(3)	M(1)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor***	D	N.A.	R	Q	*
e. Sampler Flow Rate Measuring Device	D	N.A.	R	Q	*

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Technical Specification Comments Section 3/4.4

3/4.4.1 Note added to allow special test exception

3/4.4.13 Combined the specifications for hot shutdown and cold shutdown (loops filled)

Objective: To allow a filled/intact reactor coolant loop to take the place of a shutdown cooling train when in Mode 5 or Mode 4 less than 280°F for the following reasons: 1) allow RCP operation at less than 150°F for RCS filling/venting operations. 2) provide RCP heat input to heat-up the plant from cold shutdown conditions, and 3) provide for isolating the Shutdown Cooling System (not the LTOP) on plant heat-up to facilitate realignment of the SDC to safety injection mode.
From the following notes and attachments it can be seen that this change involves no reduction in 1) low temperature over pressure protection (LTOP), 2) core decay heat removal capability, 3) boron mixing capability.

Note #: Delete this statement as the intent is to provide for LTOP at less than 280°F, shutdown cooling does not need to be in operation to provide LTOP and the requirement to provide for LTOP at less than 235°F is covered by Technical Specification 3.4.8.3.1 (page 3/4 4-33).

Also note that this change is supported by the bases for this section.

3/4.8.1 Added the changes in the H/U and C/D Specs per C-E submittal.

NOTE: A proposed Reactor Coolant Gas Vent System Technical Specification was submitted previously. It is our intention to utilize this system as described in our response to NUREG 0737. Operability will be demonstrated in conformance with ASME Section IX requirements.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

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STARTUP AND POWER OPERATION

LIMITING CONDITION FOR OPERATION

3.4.1 Both Reactor Coolant loops and associated steam generator and both Reactor Coolant pumps in each loop shall be in operation.

APPLICABILITY: 1 and 2.*

ACTION:

With less than the above required Reactor Coolant pumps in operation, be in at least HOT STANDBY within 1 hour.

SURVEILLANCE REQUIREMENTS

4.4.1 The above required Reactor Coolant loops shall be verified to be in operation and circulating Reactor Coolant at least once per 12 hours.

*See Special Test Exception 3.10.3. and 3.10.6

REACTOR COOLANT SYSTEM

HOT SHUTDOWN ~~and cold shutdown (loops~~ (FILLED)

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LIMITING CONDITION FOR OPERATION

3.4.1.3 a. At least two of the loop(s)~~/train(s)~~ and or ~~shutdown cooling~~ trains(s) listed below shall be OPERABLE:

1. Reactor Coolant Loop 1 and its associated steam generator and at least one associated Reactor Coolant pump,**
2. Reactor Coolant Loop 2 and its associated steam generator and at least one associated Reactor Coolant pump,**
3. Shutdown Cooling Train A,
4. Shutdown Cooling Train B.

b. At least one of the above Reactor Coolant loops and/or shutdown cooling trains shall be in operation.*

APPLICABILITY: MODE ~~#~~ 4 and 5 (Loops filled)

ACTION:

a. With less than the above required Reactor Coolant loops and/or shutdown cooling trains OPERABLE, immediately initiate corrective action to return the required loops/trains to OPERABLE status as soon as possible; if the remaining OPERABLE loop is a shutdown cooling train, be in COLD SHUTDOWN within 24 hours.

b. With no Reactor Coolant loop or shutdown cooling train in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required coolant loop/ train to operation.

~~# With the Reactor Coolant System cold leg temperature less than or equal to 200°F, the shutdown cooling system shall be in operation with all suction line valves open.~~

* All Reactor Coolant pumps and shutdown cooling pumps may be de-energized for up to 1 hour provided (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

** ~~1 Reactor Coolant pump shall not be started if the associated steam generator to Reactor Coolant System delta-T is greater than 100°F and/or if Reactor Coolant System cold leg temperature is less than or equal to 200°F.~~

See following PAGE

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REACTOR COOLANT SYSTEM

HOT SHUTDOWN

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required Reactor Coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.3.2 The required steam generator(s) shall be determined OPERABLE by verifying the secondary side water level to be $\geq$ 10% (wide range) at least once per 12 hours.

4.4.1.3.3 At least one Reactor Coolant loop or shutdown cooling train shall be verified to be in operation and circulating Reactor Coolant at least once per 12 hours.

previous page

**A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to ~~(275)~~ 180°F unless 1) the pressurizer water volume is less than ~~(900)~~ 1000 cubic feet or 2) the secondary water temperature of each steam generator is less than ~~(46)~~ 100°F above each of the RCS cold leg temperatures.

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REACTOR COOLANT SYSTEM

COLD SHUTDOWN - LOOPS FILLED

DELETE - combined with 3.4.1.3

LIMITING CONDITION FOR OPERATION

3.4.1.4.1 At least one shutdown cooling train shall be OPERABLE with all suction line valves open and in operation,* and either:

a. One additional shutdown cooling train shall be OPERABLE,# or

b. The secondary side water level of at least two steam generators shall be greater than 10%.

APPLICABILITY: MODE 5#, with Reactor Coolant loops filled.

ACTION:

a. With less than the above required shutdown trains/loops OPERABLE or with less than the required steam generator level, immediately initiate corrective action to return the required trains/loops to OPERABLE status or restore the required level as soon as possible.

b. With no shutdown cooling train in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required shutdown cooling train to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.1.1 The secondary side water level of at least two steam generators, when required, shall be determined to be within limits at least once per 12 hours.

4.4.1.4.1.2 The shutdown cooling train shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One shutdown cooling train may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling train is OPERABLE and in operation.

*The shutdown cooling pump may be de-energized for up to 1 hour provided 1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.4.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed ~~after 6 Effective Full Power Months but within 24 calendar months of initial criticality.~~ At the first refueling outage Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in both sets of inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 at 40 month intervals fall into Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.4.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tubes leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.5.2.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

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REACTOR COOLANT SYSTEM

3/4.4.8 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.8.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4-2 and Figure 3.4-3 during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A maximum heatup of ~~60~~ 30°F in any one hour period for RCS cold leg temperatures 280°F and a maximum heatup of 100°F in any one hour period for RCS cold leg temperatures above 280°F.

b. A maximum cooldown of 100°F in any one hour period for RCS temperatures above ~~200~~ 280°F; a maximum cooldown of ~~60~~ 30°F in any one hour period for temperatures below ~~200~~ 180°F.

c. A maximum temperature change of less than or equal to 10°F in any one hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limit within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operations or be in at least HOT STANDBY within the next 6 hours and reduce the RCS T_{avg} and pressure to less than 200°F and 500 psia, respectively, within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.8.1.1 The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

4.4.8.1.2 The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties, at the intervals required by 10 CFR 50 Appendix H in accordance with the schedule in Table 4.4-5. The results of these examinations shall be used to update Figures 3.4-2 and 3.4-3 based on the greater of the following:

a. The actual shift in reference temperature for plate C-6404-2 as determined by impact testing, or

b. The predicted shift in reference temperature for either weld seams 3-203A or 3-203B, as-delete

REACTOR COOLANT SYSTEM

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OVERPRESSURE PROTECTION SYSTEMS

RCS TEMPERATURE $\leq$ ~~200~~ 235 °F

LIMITING CONDITION FOR OPERATION

3.4.8.3.1 At least one of the following overpressure protection systems shall be OPERABLE:

a. The Shutdown Cooling System (SDCS) Relief Valve (PSV9349) with a lift setting of less than or equal to 402 psig, or,

b. The Reactor Coolant System depressurized with an RCS vent of greater than or equal to 5.6 square inches.

APPLICABILITY: Mode 4 when the temperature of one any RCS cold leg is less than or equal to ~~200~~ 235 °F; Mode 5; Mode 6 with the reactor vessel head on.

ACTION:

a. With the SDCS Relief Valve inoperable, be in at least COLD SHUTDOWN, depressurize and vent the RCS through a greater than or equal to 5.6 square inch vent within the next 8 hours.

b. In the event either the SDCS Relief Valve or an RCS vent is used to mitigate a RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the SDCS Relief Valve or RCS vent on the transient and any corrective action necessary to prevent recurrence.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.8.3.1.1 The SDCS Relief Valve shall be demonstrated OPERABLE by:

~~a. Verification of the SDCS Relief Valve setpoint at least once per 30 months.~~

SURVEILLANCE REQUIREMENTS (Continued)

a. Verifying the SDCS Relief Valve isolation valves (valves 2HV9337, 2HV9339, 2HV9377, and 2HV9378) are locked open in the control room at least once per 72 hours when the SDCS Relief Valve is being used for overpressure protection.

b. Testing pursuant to Specification 4.0.5. Inservice test intervals shall not exceed 30 months.

4.4.8.3.1.2 The RCS vent shall be verified to be open at least once per 12 hours* when the vent is being used for overpressure protection.

*Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

REACTOR COOLANT SYSTEM

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OVERPRESSURE PROTECTION SYSTEMS

RCS TEMPERATURE > ~~280~~ 235 °F

LIMITING CONDITION FOR OPERATION

3.4.8.3.2 At least one of the following overpressure protection systems shall be OPERABLE:

a. The Shutdown Cooling System (SDCS) Relief Valve (PSV 9349) with a setting of less than or equal to 402 psig, or,

b. A minimum of one pressurizer code safety valve with a lift setting of 2500 psia ± 1%*.

APPLICABILITY: MODE 4 with RCS temperature above ~~280~~ 235 °F.

ACTION:

With no safety or relief valve operable, be in cold shutdown and vent the RCS through a greater than or equal to 5.6 square inch vent within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.4.8.3.2.1 The SDCS Relief Valve shall be demonstrated operable by:

a. Verifying the SDCS Relief Valve isolation valves are open at least once per 72 hours when the SDCS Relief Valve is being used for overpressure protection.

b. Testing pursuant to Specification 4.0.5. Inservice test intervals shall not exceed 30 months.

4.4.8.3.2.2 The pressurizer code safety valve has no additional surveillance requirements other than those required by Specification 4.0.5.

4.4.8.3.2.3 The RCS vent shall be verified to be open at least once per 12 hours when the vent is being used for overpressure protection, except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

Technical Specification Comments Section 3/4.5

4.5.2 ECCS head/flow and flow balance criteria have been provided.

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SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the safety injection tank solution.

d. At least once per 31 days when the RCS pressure is above 514 psia, by verifying that the isolation valve operator breakers are padlocked in the open position.

e. At least once per 18 months by verifying that each safety injection tank isolation valve opens automatically under each of the following conditions:

1. Before ~~an actual or~~ simulated RCS pressure signal exceeds ~~505~~ 515 psia, and
2. Upon receipt of a safety injection test signal.

The fuses removed for [illegible]

c. At least once per 31 days by verifying [illegible] each safety injection tank vent valve.

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2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or abnormal corrosion.

e. At least once per 18 months, during shutdown, by:

1. Verifying that each automatic valve in the flow path actuates to its correct position on SIAS and RAS test signals.

2. Verifying that each of the following pumps start automatically upon receipt of a Safety Injection Actuation Test Signal:

a. High-Pressure Safety Injection pump.

b. Low-Pressure Safety Injection pump.

c. Charging pump.

3. Verifying that on a Recirculation Actuation Test Signal, the containment sump isolation valves open and the recirculation valves to the refueling water tank close.

f. By verifying that each of the following pumps ~~develops~~ Provides the indicated developed head or flow rate when tested pursuant to Specification 4.0.5:

1. High-Pressure Safety Injection pump developed head greater than or equal to 2113 feet for P017, 2076 feet for P018 and 2075 feet for P019

2. Low-Pressure Safety Injection pump developed head greater than or equal to 406.1 ft.

3. Charging pump flow rate greater than or equal to 40 gpm.

g. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying the following flow rates:

SURVEILLANCE REQUIREMENTS (Continued)

HPSI System - Single Pump

~~a. Injection Leg 1, greater than or equal to ____ gpm~~

~~b. Injection Leg 2, greater than or equal to ____ gpm~~

~~c. Injection Leg 3, greater than or equal to ____ gpm~~

~~d. Injection Leg 4, greater than or equal to ____ gpm~~

LPSI System - Single Pump

~~a. Injection Leg 1, greater than or equal to ____ gpm~~

~~b. Injection Leg 2, greater than or equal to ____ gpm~~

~~c. Injection Leg 3, greater than or equal to ____ gpm~~

~~d. Injection Leg 4, greater than or equal to ____ gpm~~

a) cold leg injection: $\frac{\Sigma \text{ three lowest cold leg flows}}{3/4} \geq 860$ gpm

b) Hot/cold leg injection Σ cold leg flows ≥ 423 gpm and hot leg flow ≥ 423 gpm

The flow through each injection leg shall be greater than or equal to 2000 gpm when tested individually and corrected to the same pump suction source and leg backpressure conditions.

h. By testing pursuant to Specification 4.0.5

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3/4.5.4 REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.4 The refueling water storage tank shall be OPERABLE with:

a. A minimum borated water volume of 362,800 gallons above the ECCS suction connection,

b. Between 1720 and 2300 ppm of boron, and

c. A solution temperature between 40°F, and ~~120~~ 100°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the refueling water storage tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The RWST shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the contained borated water volume in the tank, and

2. Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is less than 40°F or greater than 100°F.

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Technical Specifications Comments Section 3/4.6

3/4.6.2.2 : The minimum NaOH volume and required temperature range have been provided. Maximum NaOH volume is not specified as this is bounded by tank volume. Automatic pump start has been added to Surveillance 4.6.2.2.d. Surveillance 4.6.2.2.e is not applicable to non-eductor systems and therefore been deleted.

Table 3.6-1 Sections C and D have been revised to delete valves for which the safe position is OPEN (for example Safety Injection header isolation valves) or which do not otherwise pertain to the containment isolation function (ie: Main Steam safety valves). Isolation of such systems could place the plant in an unsafe condition.

CONTAINMENT SYSTEMS

IODINE REMOVAL SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The iodine removal system shall be OPERABLE with:

a. A spray additive tank containing a minimum solution volume of ~~between~~ 1456 ~~and~~ ____ gallons of between 40 and 44% by weight NaOH solution with a ~~minimum~~ solution temperature ~~of~~ between 82°F and 88°F, and

b. Two spray chemical addition pumps each capable of adding NaOH solution from the chemical addition tank to a containment spray system pump flow.

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

ACTION:

With the iodine removal system inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the spray additive system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The iodine removal system shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying the NaOH solution temperature.

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. At least once per 6 months by:

1. Verifying the contained solution volume in the tank, and

2. Verifying the concentration of the NaOH solution by chemical analysis.

d. At least once per 18 months, during shutdown, by verifying (1) that each automatic valve in the flow path actuates to its correct position on a Containment Spray Actuation test signal, and (2) that each spray chemical addition pump starts automaticly on a containment spray actuation test signal.

~~e. At least once per 5 years by verifying each solution flow rate (to be determined during pre-operational tests) from the following drain connections in the spray additive system:~~

~~1. (Drain line location) ____ ± ____ gpm.~~

~~2. (Drain line location) ____ ± ____ gpm.~~

* When Shutdown Cooling System not in operation.

TABLE 3.6-1 (Continued)

PENETRATION NUMBER	VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (SEC)
C. MANUAL			
5	2"-699-C-376*	Safety injection drain to RWST	NA
~~6~~	~~HV-9200~~	~~Charging line to regenerative heat exchanger~~	~~NA~~
~~9~~	~~HV-9337#@~~	~~Shutdown cooling to LPSI pumps~~	~~NA~~
~~9~~	~~HV-9377#@~~	~~Shutdown cooling to LPSI pumps~~	~~NA~~
~~9~~	~~HV-9336#@~~	~~Shutdown cooling to LPSI pumps~~	~~NA~~
~~9~~	~~HV-9379#@~~	~~Shutdown cooling to LPSI pumps~~	~~NA~~
~~16A~~	~~HV-6552A#~~	~~Containment pressure detectors~~	~~NA~~
16B	3/4"-038-C-396	Integrated leak rate test pressure sensor	NA
16C	3/4"-039-C-396	Integrated leak rate test pressure sensor	NA
~~16A~~	~~HV-9463~~	~~Post-LOCA hydrogen monitor~~	~~NA~~
~~16A~~	~~HV-9461~~	~~Post-LOCA hydrogen monitor~~	~~NA~~
~~16B~~	~~HV-9462~~	~~Post-LOCA hydrogen monitor~~	~~NA~~
~~16B~~	~~HV-9463~~	~~Post-LOCA hydrogen monitor~~	~~NA~~
20	2"-331-C-376	Quench tank makeup ←=(STET)	NA
21	2"-055-C-387	Service air supply line	NA
25	10"-100-C-212	Refueling canal fill and drain	NA
25	10"-101-C-212	Refueling canal fill and drain	NA
~~44A~~	~~HV-6552B#~~	~~Containment pressure detectors~~	~~NA~~
31	HV-9946	Containment hydrogen purge inlet	NA
31	HCV-9945	Containment hydrogen purge inlet	NA
~~46A~~	~~HV-6552B#~~	~~Containment pressure detectors~~	~~NA~~
67	HV-9434	Hot leg injection	NA
68	2"-130-C-334	Charging line to auxiliary spray	NA
70	2"-037-C-387	Auxiliary steam inlet to utility stations	NA
70	2"-038-C-387	Auxiliary steam inlet to utility stations	NA
71	HV-9420	Hot leg injection	NA
~~72A~~	~~HV-6552C#~~	~~Containment pressure detectors~~	~~NA~~
74	HV-9517	Containment hydrogen purge outlet	NA
74	HCV-9518	Containment hydrogen purge outlet	NA

ADD ATTACHED PAGE

TABLE 3.6-1 (Continued)

PENETRATION NUMBER	VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (SEC)
D. OTHER			
3	3"-018-A-551#	High pressure safety injection	NA
~~3~~	~~HV-9323#~~	~~High pressure safety injection~~	~~NA~~
~~3~~	~~HV-9324#~~	~~High pressure safety injection~~	~~NA~~
5	3"-019-A-551#	High pressure safety injection	NA
~~5~~	~~HV-9326#~~	~~High pressure safety injection~~	~~NA~~
~~5~~	~~HV-9327#~~	~~High pressure safety injection~~	~~NA~~
8	2"-122-C-554	Charging line to regenerative heat exchanger	NA
9	PSV-9349	Shutdown cooling relief	NA
11	3"-236-C-675	Demineralized water to service stations and sump pump	NA
14	4"-061-C-681	Fire protection	NA
17	HV-4058#*	Steam generator secondary coolant sample	NA
20	2"-573-C-611	Quench tank makeup	NA
21	2"-017-C-627	Service air supply line	NA
22	1-1/2"-016-C-617	Instrument air supply line	NA
23A	3/4"-002-C-611	LP N_2 to containment	NA
~~32~~	~~HV-8421#~~	~~Mainsteam atmospheric dump~~	~~NA~~
32	PSV-8410#	Mainsteam relief	NA
32	PSV-8411#	Mainsteam relief	NA
32	PSV-8412#	Mainsteam relief	NA
32	PSV-8413#	Mainsteam relief	NA
32	PSV-8414#	Mainsteam relief	NA
32	PSV-8415#	Mainsteam relief	NA
32	PSV-8416#	Mainsteam relief	NA
32	PSV-8417#	Mainsteam relief	NA
32	PSV-8418#	Mainsteam relief	NA
32	HV-8249B#	Mainsteam trap isolation	NA
32	HV-8202#	Mainsteam isolation bypass	NA
32	HV-8200#	Mainsteam to auxiliary feedwater turbine	NA
33	HV-8419#	Mainsteam atmospheric dump	NA
~~33~~	~~PSV-8401#~~	~~Mainsteam relief~~	~~NA~~

TABLE 3.6-1 (Continued)

PENETRATION NUMBER	VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (SEC)
~~33~~	~~PSV-8402#~~	~~Mainsteam relief~~	~~NA~~
33	PSV-8403#	Mainsteam relief	NA
33	PSV-8404#	Mainsteam relief	NA
33	PSV-8405#	Mainsteam relief	NA
33	PSV-8406#	Mainsteam relief	NA
33	PSV-8407#	Mainsteam relief	NA
33	PSV-8408#	Mainsteam relief	NA
33	PSV-8409#	Mainsteam relief	NA
33	~~HV-8248B#~~	Mainsteam trap isolation	NA
33	HV-8203#	Mainsteam isolation bypass	NA
~~33~~	~~HV-8201#~~	~~Mainsteam to auxiliary feedwater turbine~~	~~NA~~
36	HV-4054#*	Steam generator blowdown	NA
37	HV-4053#*	Steam generator blowdown	NA
39	3"-020-A-551	High pressure safety injection	NA
~~39~~	~~HV-9329#~~	~~High pressure safety injection~~	~~NA~~
~~39~~	~~HV-9330#~~	~~High pressure safety injection~~	~~NA~~
41	3"-021-A-551	High pressure safety injection	NA
~~41~~	~~HV-9332#~~	~~High pressure safety injection~~	~~NA~~
~~41~~	~~HV-9333#~~	~~High pressure safety injection~~	~~NA~~
42	HV-6223	Component cooling water inlet	NA
43	HV-6236	Component cooling water inlet	NA
44	HV-4057#*	Steam generator secondary coolant sample	NA
48	8"-072-A-552#@	Low pressure safety injection	NA
~~48~~	~~HV-9322#@~~	~~Low pressure safety injection~~	~~NA~~
49	8"-073-A-552#@	Low pressure safety injection	NA
~~49~~	~~HV-9325#@~~	~~Low pressure safety injection~~	~~NA~~
50	8"-074-A-552#@	Low pressure safety injection	NA
~~50~~	~~HV-9328#@~~	~~Low pressure safety injection~~	~~NA~~
51	8"-075-A-552#@	Low pressure safety injection	NA
~~51~~	~~HV-9331#@~~	~~Low pressure safety injection~~	~~NA~~
52	8"-004-C-406	Containment spray inlet	NA
~~52~~	~~HV-9367~~	~~Containment spray inlet~~	~~NA~~

TABLE 3.6-1 (Continued)

PENETRATION NUMBER	VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (SEC)
53	8"-006-C-406	Containment spray inlet	NA
~~53~~	~~HV-9368~~	~~Containment spray inlet~~	~~NA~~
54	HV-9304#	Containment emergency sump recirculation	NA
54	HV-9302#	Containment emergency sump recirculation	NA
55	HV-9305#	Containment emergency sump recirculation	NA
55	HV-9303#	Containment emergency sump recirculation	NA
56	HV-6366	Containment emergency A/C cooling water inlet	NA
57	HV-6372	Containment emergency A/C cooling water inlet	NA
58	HV-6368	Containment emergency A/C cooling water inlet	NA
59	HV-6370	Containment emergency A/C cooling water inlet	NA
60	HV-6369	Containment emergency A/C cooling water inlet	NA
61	HV-6371	Containment emergency A/C cooling water inlet	NA
62	HV-6367	Containment emergency A/C cooling water inlet	NA
~~63~~	~~HV-6373~~	~~Containment emergency A/C cooling water inlet~~	~~NA~~
67	3"-157-A-551	Hot leg injection	NA
68	2"-129-A-554	Charging line to auxiliary spray	NA
71	3"-158-A-551	Hot leg injection	NA
~~75~~	~~HV-4715#~~	~~Steam generator auxiliary feedwater~~	~~NA~~
~~75~~	~~HV-4731#~~	~~Steam generator auxiliary feedwater~~	~~NA~~
77	2"-108-C-627	Nitrogen supply to safety injection tanks	NA
~~78~~	~~HV-4714#~~	~~Steam generator auxiliary feedwater~~	~~NA~~
~~78~~	~~HV-4730#~~	~~Steam generator auxiliary feedwater~~	~~NA~~

*May be opened on an intermittent basis under administrative control.

**Power to the valve removed in accordance with Specification 3.6.1.7.

#Not subject to Type C leakage tests.

@Shutdown cooling valves may be opened in MODE 4.

Technical Specifications Comments Section 3/4.7

Table 3.7-2: Revised per adoption of standard-based formula in Bases.

4.7.5.e.4: Deleted. This test is required to be performed only once, during preoperational testing, for systems with greater than 0.06 air changes per hour. Periodic testing is not required by either R.G 1.78,1.95 or SRP 6.4.

Table 3.7-4b: Revised per format of V.C.Summer Technial Specifications .

TABLE 3.7-2

MAXIMUM ALLOWABLE LINEAR POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Linear Power Level-High Trip Setpoint (Percent of RATED THERMAL POWER)
1	~~90~~ 90.9
2	~~79~~ 79.6
3	~~68~~ 68.2
4	~~57~~ 56.8
5	~~45~~ 45.5
6	~~34~~ 34.1
7	~~23~~ 22.7
8	~~0~~ 0

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SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the cleanup system satisfies the in-place testing acceptance criteria and uses the test procedures of Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 1000 cfm ± 10% for the ventilation unit and 35,485 cfm ± 10% for the air conditioning unit.

3. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

4. Verifying a system flow rate of 1000 cfm ± 10% for the ventilation unit and 35,485 cfm ± 10% for the air conditioning unit during system operation when tested in accordance with ANSI N510-1975.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

e. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 4.3 inches Water Gauge ventilation unit and less than 7.3 inches Water Gauge air conditioning unit while operating the system at a flow rate of 1000 cfm ± 10% for the ventilation unit and 35,485 cfm ± 10% for the air conditioning unit.

2. Verifying that on a control room isolation test signal, the system automatically switches into the emergency mode of operation with flow through the HEPA filters and charcoal adsorber banks.

3. Verifying that on a toxic gas isolation test signal, the system automatically switches into the isolation mode of operation with flow through the HEPA filters and charcoal adsorber banks.

~~4. Verifying that the system maintains the control room at a positive pressure of greater than or equal to 1/8 inch W.G. relative to the outside atmosphere during system operation in the emergency mode.~~ X

4,5. Verifying that the heaters dissipate 3.2 kw ± 5% when tested in accordance with ANSI N510-1975. X

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Table 3.7-4b

Safety-Related Mechanical Snubbers*

System	Size							
	Small		Medium			Large		
	1/4	1/2	1	3	6	10	35	100
RC	39	12	15	34		16	9	3
ST	29	3	20	12		9	5	22
BM	18	11						
CC	19	24	16	4		4	2	
SS	34	1	2					
SI	86	48	51	46		20	13	1
FW	1	4	2	4		13	2	
FS	3	18	10	5				
VC	39	18	9					
CS	5	14	25	16				
SC				4		3	2	
CH		1						
CB			4					
GR	4							
CEDM				4	212			
Subtotal-1	277	154	154	129	212	65	33	26
Subtotal-2	431		560			59		
Total	1050							

*Snubbers may be added to safety-related systems without prior License Amendment to Table 3.7-4b provided that a revision to Table 3.7-4b is included with the next License Amendment request.

~~San Onofre Unit 2~~

San Onofre UNIT-2

Technical Specifications Comments Section 3/4.8

3/4.8.8: The second "physically independent circuit between the offsite transmissio network and the onsite Class 1E distribution system" is either the Unit 3 Reserve Auxiliary transformer or the unit 2 Unit Auxiliary transformer (with the generator disconnect links removed). It is our intention to utilize the unit 2 Unit Auxiliary Transformer (with the disconnect links removed).

The following Unit 3 electrical systems will be required to support use of the Unit 3 Reserve Auxiliary Transformer as a second source of offsite power:

1. 4160V Emergency Bus #3A04
2. 4160V Emergency Bus #3A06
3. 480V Emergency Bus #3B04
4. 480V Emergency Bus #3B06
5. 120VAC Vital Bus #3Y01
6. 120VAC Vital Bus #3Y02
7. 125VDC Bus #3D1
8. 125VDC Bus #3D2

3/4.8.4.1 : Tripping of the inoperable device has been added as an alternative to tripping the associated backup breaker. This is considered acceptable since manual tripping of the device has the same result as automatic tripping (if it were operable)--namely, protection of the penetration. It is noted that Unit 3 125V DC Bus #3D5 energized from non-iE battery bank 3B006 provides the control power to the backup breakers for the Unit 2 Reactor Coolant Pumps.

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3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.1 All containment penetration conductor overcurrent protective devices shown in Table 3.8-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the containment penetration conductor overcurrent protective device(s) shown in Table 3.8-1 inoperable:

a. Restore the protective device(s) inoperable device or the to OPERABLE status or de-energize the circuits(s) by tripping the associated backup circuit breaker within 72 hours, declare the affected system or component inoperable, and verify the backup circuit breaker to be tripped at least once per 7 days thereafter; the provisions of Specification 3.0.4 are not applicable to overcurrent devices in circuits which have their backup circuit breakers tripped, or

b. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.4.1 All containment penetration conductor overcurrent protective devices shown in Table 3.8-1 shall be demonstrated OPERABLE:

a. At least once per 18 months:

1. By verifying that the medium voltage (4-15 KV) circuit breakers are OPERABLE by selecting, on a rotating basis, at least 10% of the circuit breakers of each voltage level, and performing the following:

(a) A CHANNEL CALIBRATION of the associated protective relays, and

(b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed and as specified in Table 3.8.1.

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 With the reactor vessel head closure bolts less than fully tensioned or with the head removed, the boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of following reactivity conditions is met:

a. Either a K_{eff} of 0.95 or less,

b. A boron concentration of greater than or equal to 1720 ppm,

APPLICABILITY: MODE 6*.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1720 ppm boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 1720 ppm, whichever is the more restrictive.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The more restrictive of the above two reactivity conditions shall be determined prior to:

a. Removing or unbolting the reactor vessel head,* and

b. Withdrawal of any full length CEA in excess of 3 feet from its fully inserted position within the reactor pressure vessel.*

4.9.1.2 The boron concentration of the reactor coolant system and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

*The reactor shall be maintained in MODE 6 whenever fuel is in the reactor vessel with the reactor vessel head closure bolts less than fully tensioned or with the head removed.

For initial fuel load, the reactivity condition shall be determined prior to inserting the first fuel assembly into the pressure vessel; 4.9.1.1.a and 4.9.1.1.b shall not apply during initial fuel load.

3/4.9.7 FUEL HANDLING MACHINE - SPENT FUEL STORAGE POOL BUILDING

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 3000 pounds shall be prohibited from travel over fuel assemblies in the storage pool.

APPLICABILITY: With fuel assemblies in the storage pool.

ACTION:

With the requirements of the above specification not satisfied, place the fuel handling machine in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.7 Fuel handling machine interlocks and physical stops which prevent fuel handling machine travel with loads in excess of 3000 pounds over fuel assemblies shall be demonstrated OPERABLE within 7 days prior to fuel handling machine use and at least once per 7 days thereafter during fuel handling machine operation.

REFUELING OPERATIONS

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent shutdown cooling trains shall be OPERABLE and at least one shutdown cooling train shall be in operation.

APPLICABILITY: MODE 6 when the water level above the top of the reactor pressure vessel flange is less than 23 feet with irradiated fuel in the Reactor Vessel

ACTION:

a. With less than the required shutdown cooling trains OPERABLE, immediately initiate corrective action to return the required shutdown cooling trains to OPERABLE status, or to establish greater than or equal to 23 feet of water above the reactor pressure vessel flange as soon as possible.

b. With no shutdown cooling train in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required shutdown cooling train to operation. Close all containment penetrations providing direct access from the containment atmophere to the outside atmosphere within 4 hours.

SURVEILLANCE REQUIREMENTS

4.9.8.2 At least one shutdown cooling train shall be verified to be in operation and circulating reactor coolant at a flow rate of greater than or equal to 4000 gpm at least once per 12 hours.

Technical Specification Comments Section 3/4.10

3/4.10.5 Added new SPECIAL TEST EXCEPTIONS Section on minimum temperature for criticality.

3/4.10.6 Added new SPECIAL TEST EXCEPTIONS Section for Natural Circulation

NEW Page
4/5/81

SPECIAL TEST EXCEPTIONS

3/4.10.5 MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.10.5 The minimum temperature for criticality limits of Specification 3.1.1.4 and the noted requirements of Tables 2.2-1, 3.3-1 and 3.3-4 may be suspended during low temperature PHYSICS TESTS provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER,

b. The reactor trip setpoints on the OPERABLE Linear Power Level - High neutron flux monitoring channels are set at $\leq$ 20% of RATED THERMAL POWER, and

c. The Reactor Coolant System temperature and pressure relationship is maintained within the acceptable region of operation shown on Figure 3.4-2.

APPLICABILITY: During startup and PHYSICS TESTS.

ACTION:

a. With the THERMAL POWER 5 percent of RATED THERMAL POWER, immediately open the reactor trip breakers.

b. With the Reactor Coolant System temperature and pressure relationship within the region of unacceptable operation on Figure 3.4-2, immediately open the reactor trip breakers and restore the temperature-pressure relationship to within its limit within 30 minutes; perform the engineering evaluation required by Specification 3.4.8.1 prior to the next reactor criticality.

SURVEILLANCE REQUIREMENTS

4.10.5.1 The Reactor Coolant System temperature and pressure relationship shall be verified to be within the acceptable region for operation of Figure 3.4-2 at least once per hour.

4.10.5.2 The THERMAL POWER shall be determined to be $\leq$ 5% of RATED THERMAL POWER at least once per hour.

4.10.5.3 Each Logarithmic Power Level and Linear Power Level channel shall be subjected to a CHANNEL FUNCTIONAL TEST within 12 hours prior to initiating low temperature PHYSICS TESTS.

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3/4.10.6 NATURAL CIRCULATION

LIMITING CONDITION FOR OPERATION

3.10.6 The noted requirements of Tables 2.2-1, 3.3-1 and 3.3-4 and the limits of Specifications 3.1.1.4 and 3.4.1, may be suspended during the performance of natural circulation testing, provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER, and

b. The reactor trip setpoints of the OPERABLE power level channels are set at less than or equal to 20% of RATED THERMAL POWER.

APPLICABILITY: During natural circulation testing.

ACTION:

With the THERMAL POWER greater than 5% of RATED THERMAL POWER, immediately trip the reactor.

SURVEILLANCE REQUIREMENTS

4.10.6.1 The THERMAL POWER shall be determined to be less than or equal to 5% of RATED THERMAL POWER at least once per hour during startup and PHYSICS TESTS.

4.10.6.2 Each logarithmic and linear power level neutron flux monitoring channel shall be subjected to a CHANNEL FUNCTIONAL TEST within 12 hours prior to initiating startup and PHYSICS TESTS.

Technical Specification Comments Section 3/4.12

3/4.12.1 Changes marked per Radiological Assessment Branch comments and location-specific data.

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.1 The radiological environmental monitoring program shall be conducted as specified in Table 3.12-1.

APPLICABILITY: At all times.

ACTION:

a. With the radiological environmental monitoring program not being conducted as specified in Table 3.12-1, in lieu of any other report required by Specification 6.9.1, prepare and submit to the Commission, in the Annual Radiological Operating Report, a description of the reasons for not conducting the program as required and the plans for preventing a recurrence.

b. With the level of radioactivity in an environmental sampling medium exceeding the reporting levels of Table 3.12-2 when averaged over any calendar quarter, in lieu of any other report required by Specification 6.9.1, prepare and submit to the Commission within 30 days from the end of the affected calendar quarter a Report pursuant to Specification 6.9.1.13. When more than one of the radionuclides in Table 3.12-2 are detected in the sampling medium, this report shall be submitted if:

$$\frac{\text{concentration (1)}}{\text{limit level (1)}} + \frac{\text{concentration (2)}}{\text{limit level (2)}} + \ldots \geq 1.0$$

When radionuclides other than those in Table 3.12-2 are detected and are the result of plant effluents, this report shall be submitted if the potential annual dose to an individual is equal to or greater than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2 and 3.11.2.3. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event, the condition shall be reported and described in the Annual Radiological Environmental Operating Report.

c. With ~~milk or~~ fresh leafy vegetable samples or fleshy vegetable samples unavailable from one or more of the sample locations required by Table 3.12-1, in lieu of any other report required by Specification 6.9.1, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause of the unavailability of samples and identifies locations for obtaining replacement samples. The locations from which samples were unavailable may then be deleted from those required by Table 3.12-1, provided the locations from which the replacement samples were obtained are added to the environmental monitoring program as replacement locations.

d. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

TABLE 3.12-1

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Samples and Sample Locations**	Sampling and Collection Frequency	Type and Frequency of Analysis
1. AIRBORNE			
Radioiodine and Particulates	~~(Locations 1-5)~~ 6	Continuous operation of sampler with sample collection as required by dust loading but at least once per 7 days and at least 10 collections per 92 days	Radioiodine ~~canister.~~ cartridge. Analyze at least once per 7 days for I-131. Particulate sampler. Analyze for gross beta radioactivity > 24 hours following filter change. Perform gamma isotopic analysis on each sample when gross beta activity is > ~~10 times the yearly mean of control samples.~~ 1 pCi/m³. Perform gamma isotopic analysis on composite (by location) sample at least once per 92 days.
2. DIRECT RADIATION	~~(Locations 6-45)~~ 51 ~~2 dosimeters or 1 Instrument for continuously measuring and recording dose rate at each location.~~ Four $CaSO_4(Dy)$ TLDs at each station collected quarterly, Two LiF TLDs at each station collected annually.	~~At least once per 31 days.~~ ~~or~~ ~~At least once per 92 days. (Read out frequencies are determined by type of dosimeters selected.)~~	~~Gamma dose. At least once per 31 days.~~ ~~or~~ Gamma dose. At least once per 92 days for $CaSO_4(Dy)$ and at least once per year for LiF.

** Sample locations are given on the figure and table in the ODCM.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Samples and Sample Locations**	Sampling and Collection Frequency	Type and Frequency of Analysis
3. WATERBORNE			
a. ~~Surface~~ Ocean	4 (Locations) ~~46 and 47~~	~~At least once per month Composite* sample collected over a period of < 31 days.~~ and composited quarterly.	monthly Gamma isotopic analysis of each ~~composite~~ sample. Tritium analysis of composite sample at least once per 92 days.
b. Ground	2 (Locations) ~~48 and 49~~	At least once per 92 days.	Gamma isotopic and tritium analyses of each sample.
c. Drinking	2 (Locations) ~~50 52~~	~~Composite* sample collected over a period of < 14 days, if I-131 analysis is performed, or~~ ~~Composite* sample collected over a period of < 31 days.~~ monthly at each location	~~I-131 analysis of each composite sample;~~ and Gamma isotopic and tritium ~~Gross beta and gamma isotopic analysis of each composite sample. Tritium analysis of composite sample at least once per 92 days.~~
d. Sediment from Shoreline	4 (locations) ~~53~~	At least once per 184 days.	Gamma isotopic analysis of each sample.
e. Ocean Bottom Sediments	(5 locations)	At least one per 184 days	Gamma isotopic analysis at each sample

* Composite samples shall be collected by collecting an aliquot at intervals not exceeding 2 hours.
**Sample locations are shown on the figure in the ODCM.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Samples and Sample Locations**	Sampling and Collection Frequency	Type and Frequency of Analysis
4. INGESTION			
~~a. Milk~~	~~(Locations 54-57)~~	~~At least once per 15 days when animals are on pasture; at least once per 31 days at other times.~~	~~Gamma isotopic and I-131 analysis of each sample~~
~~b.~~ a. Non-migratory ~~Fish and Invertebrates~~ Marine Animals	3 (Locations ~~58 and 59~~)	One sample in season, or at least once per 184 days if not seasonal. One sample of each of the following species: 1. ~~Fish~~ - 2 adult species such as perch or sheepshead 2. ~~Crustacea~~ - such as crab or lobster 3. ~~Mollusks~~ - such as limpets or seashores	Gamma isotopic analysis on edible portions.
~~c.~~ b. Local Crops ~~Food Products~~	2 (Locations ~~60-62~~)	~~At time of harvest. One sample of each of the following classes of food products:~~ Representative vegetables, normally 1 leafy and 1 fleshy collected at harvest time. At least 2 vegetables collected semiannually from each location.	Gamma isotopic analysis on edible portion.
c. Kelp	4 (Location ~~63~~)	~~At time of harvest. One sample of broad leaf vegetation.~~ least once per 184 days.	~~Gamma isotopic analysis I-131 analysis~~ and tritium analysis
d. Broadleaf vegetation	(2 Locations)	Monthly	Monthly gamma isotopic analysis.
5. Other a. Soil	(5 locations)	At least once per year	
b. Rabbit	(1 location)	At least once per 184 days	Thyroid analyzed for I-131; Femur analyzed for Sr-89 and gamma isotopic analysis

**Sample locations are shown on the figure in the ODCM.

TABLE 3.12-2

REPORTING LEVELS FOR RADIOACTIVITY CONCENTRATIONS IN ENVIRONMENTAL SAMPLES

Analysis	Reporting Levels: Water (pCi/l)	Airborne Particulate or Gases (pCi/m³)	~~Fish~~ Marine Animals (pCi/Kg, wet)	~~Milk (pCi/l)~~	~~Food Products~~ Local Crops (pCi/Kg, wet)
H-3	2×10^4 (a)				
Mn-54	1×10^3		3×10^4		
Fe-59	4×10^2		1×10^4		
Co-58	1×10^3		3×10^4		
Co-60	3×10^2		1×10^4		
Zn-65	3×10^2		2×10^4		
Zr-Nb-95	4×10^2				
I-131	2	0.9		~~3~~	1×10^2
Cs-134	30	10	1×10^3	~~60~~	1×10^3
Cs-137	50	20	2×10^3	~~70~~	2×10^3
Ba-La-140	2×10^2			~~3×10^2~~	

(a) For drinking water samples. This is 40 CFR Part 141 value.

RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.3 Analyses shall be performed on radioactive materials supplied as part of an Interlaboratory Comparison Program which has been approved by the Commission.

APPLICABILITY: At all times.

ACTION:

a. With analyses not being performed as required above, report the corrective actions taken to prevent a recurrence to the Commission in the Annual Radiological Environmental Operating Report.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.12.3 A summary of the results obtained as part of the above required Interlaboratory Comparison Program and in accordance with the ODCM ~~(for participants in the EPA crosscheck program shall provide the EPA program code designation for the units)~~ shall be included in the Annual Radiological Environmental Operating Report.

BASES

3/4.2.1 LINEAR HEAT RATE

The limitation on linear heat rate ensures that in the event of a LOCA, the peak temperature of the fuel cladding will not exceed 2200°F.

Either of the two core power distribution monitoring systems, the Core Operating Limit Supervisory System (COLSS) and the Local Power Density channels in the Core Protection Calculators (CPCs), provide adequate monitoring of the core power distribution and are capable of verifying that the linear heat rate does not exceed its fts limits. The COLSS performs this function by continuously monitoring the core power distribution and calculating a core power operating limit corresponding to the allowable peak linear heat rate. Reactor operation at or below this calculated power level assures that the limits of 13.9 kw/ft are not exceeded.

The COLSS calculated core power and the COLSS calculated core power operating limits based on linear heat rate are continuously monitored and displayed to the operator. A COLSS alarm is annunciated in the event that the core power exceeds the core power operating limit. This provides adequate margin to the linear heat rate operating limit for normal steady state operation. Normal reactor power transients or equipment failures which do not require a reactor trip may result in this core power operating limit being exceeded. In the event this occurs, COLSS alarms will be annunciated. If the event which causes the COLSS limit to be exceeded results in conditions which approach the core safety limits, a reactor trip will be initiated by the Reactor Protective Instrumentation. The COLSS calculation of the linear heat rate includes appropriate penalty factors which provide, with a 95/95 probability/ confidence level, that the maximum linear heat rate calculated by COLSS is conservative with respect to the actual maximum linear heat rate existing in the core. These penalty factors are determined from the uncertainties associated with planar radial peaking measurement, engineering ~~heat flux uncertainty,~~ factors axial densification, software algorithm modelling, computer processing, rod bow and core power measurement.

Parameters required to maintain the operating limit power level based on linear heat rate, margin to DNB and total core power are also monitored by the CPCs assuming minimum core power of 20% RATED THERMAL POWER. The 20% Rated Thermal Power threshold is due to the neutron flux detector system being inaccurate below 20% core power. Core noise level at low power is too large to obtain usable detector readings. Therefore, in the event that the COLSS is not being used, operation within the limits of Figure 3.2-2 can be maintained by utilizing a predetermined local power density margin and a total core power limit in the CPC trip channels. The above listed uncertainty penalty factors plus those associated with startup test acceptance criteria are also included in the CPCs.

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AZIMUTHAL POWER TILT - T_q (Continued)

T_q is the peak fractional tilt amplitude at the core periphery

g is the radial normalizing factor

θ is the azimuthal core location

θ_o is the azimuthal core location of maximum tilt

P_{tilt}/P_{untilt} is the ratio of the power at a core location in the presence of a tilt to the power at that location with no tilt.

3/4.2.4 DNBR MARGIN

The limitation on DNBR as a function of AXIAL SHAPE INDEX represents a conservative envelope of operating conditions consistent with the safety analysis assumptions and which have been analytically demonstrated adequate to maintain an acceptable minimum DNBR throughout all anticipated operational occurrences, of which the loss of flow transient is the most limiting. Operation of the core with a DNBR at or above this limit provides assurance that an acceptable minimum DNBR will be maintained in the event of a loss of flow transient.

Either of the two core power distribution monitoring systems, the Core Operating Limit Supervisory System (COLSS) and the DNBR channels in the Core Protection Calculators (CPCs), provide adequate monitoring of the core power distribution and are capable of verifying that the DNBR does not violate its limits. The COLSS performs this function by continuously monitoring the core power distribution and calculating a core operating limit corresponding to the allowable minimum DNBR. Reactor operation at or below this calculated power level assures that the limits of Figure 3.2-1 are not violated. The COLSS calculation of core power operating limit based on the minimum DNBR limit includes appropriate penalty factors which provide, with a 95/95 probability/confidence level, that the core power limit calculated by COLSS (based on the minumum DNBR limit) is conservative with respect to the actual core power limit. These penalty factors are determined from the uncertainties associated with planar radial peaking measurement, engineering ~~heat flux~~ factors, state parameter measurement, software algorithm modelling, computer processing, rod bow and core power measurement.

Parameters required to maintain the margin to DNB and total core power are also monitored by the CPCs. Therefore, in the event that the COLSS is not being used, operation within the limits of Figure 3.2-2 can be maintained by utilizing a predetermined DNBR as a function of AXIAL SHAPE INDEX and by monitoring the CPC trip channels. The above listed uncertainty penalty factors plus those associated with startup test acceptance criteria are also included in the CPC's which assume a minimum core power of 20% of RATED THERMAL POWER. The 20% Rated Thermal Power threshold is due to the neutron flux detector system being inaccurate below 20% core power. Core noise level at low power is too large to obtain usable detector readings.

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BASES

~~3/4.2.5 RCS FLOW RATE~~

~~This specification is provided to ensure that the actual RCS total flow rate is maintained at or above the minimum value used in the LOCA safety analyses.~~

~~3/4.2.6 CORE AVERAGE COOLANT TEMPERATURE~~

~~This specification is provided to ensure that the assumptions used for the initial conditions of the LOCA safety analyses remain valid.~~

3/4.2.5 RCS FLOW RATE

This specification is provided to ensure that the actual RCS total flow rate is maintained at or above the minimum value used in the LOCA safety analyses.

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

This specification is provided to ensure that the actual value of reactor coolant cold leg temperature is maintained within the range of values used in the safety analyses.

3/4.2.7 AXIAL SHAPE INDEX

This specification is provided to ensure that the actual value of AXIAL SHAPE INDEX is maintained within the range of values used in the safety analyses.

3/4.2.8 PRESSURIZER PRESSURE

This specification is provided to ensure that the actual value of pressurizer pressure is maintained within the range of values used in the safety analyses.

DRAFT

BASES

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with both reactor coolant loops and associated reactor coolant pumps in operation, and maintain DNBR above 1.30 during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation, this specification requires that the plant be in at least HOT STANDBY within 1 hour.

In MODE 3, a single reactor coolant loop provides sufficient heat removal capability for removing decay heat; however, single failure considerations require that two loops be OPERABLE.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or shutdown cooling train provides sufficient heat removal capability for removing decay heat; but single failure considerations require that at least two loops/trains (either RCS or shutdown cooling) be OPERABLE.

In MODE 5 with reactor coolant loops not filled, a single shutdown cooling train provides sufficient heat removal capability for removing decay heat; but single failure considerations, and the unavailability of the steam generators as a heat removing component, require that at least two shutdown cooling trains be OPERABLE.

The operation of one Reactor Coolant Pump or one shutdown cooling pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump in Modes 4 and 5 with one or more RCS cold legs less than or equal to 280°F are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by either (1) restricting the water volume in the pressurizer and thereby providing a volume for the primary coolant to expand into or (2) by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 100°F above each of the RCS cold leg temperatures.

3/4.4.2 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2750 psia. Each safety valve is designed to relieve 4.6 x 10^5 lbs per hour of saturated steam at the valve setpoint plus 3% accum ulation The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no RCS cold leg temperature >235°F. safety valves are OPERABLE, ~~an operating~~ shutdown cooling ~~loop~~ connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. ~~In addition, the Overpressure Protection System provides a diverse means of protection against RCS overpressurization at low temperatures.~~

PRESSURE/TEMPERATURE LIMITS (Continued)

The OPERABILITY of the Shutdown Cooling System relief valve or a RCS vent opening of greater than ~~(1.3)~~ 5.6 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to ~~(275)~~ 280°F. The Shutdown Cooling System relief valve has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to ~~(46)~~ 100°F above the RCS cold leg temperatures or (2) ~~the start of a~~ inadvertant safety injection actuation with two HPSI pumps ~~and its~~ with full charging capacity injecting into a water solid RCS and letdown isolated.)

3/4.4.9 STRUCTURAL INTEGRITY

The inservice inspection and testing programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity and operational readiness of these components will be maintained at an acceptable level throughout the life of the plant. These programs are in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the Commission pursuant to 10 CFR Part 50.55a (g) (6) (i).

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1974 Edition and Addenda through Summer 1975.

When cold leg temperature is less than 280 °F, RCS heatup and cooldown rates are restricted to less than 30 °F/hr. These limitations are provided in order to relax the requirements for alignment of a relief valve for RCS low temperature overpressure protection (LTOP). Based on the 30°F/hr heatup and cooldown rates for the 0 - 5 year period of plant operation (Figure 3.4-2 and 3.4-3), alignment of the LTOP relief valve is only required when cold leg temperature is less than 235 °F. The Shutdown Cooling System relief valve is used to provide LTOP.

ECCS SUBSYSTEMS (Continued)

With the RCS temperature below 350°F, one OPERABLE ECCS subsystem is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

The NaOH added to the Containment Spray, via the Spray Chemical Addition pumps, minimizes the possibility of corrosion cracking of certain metal components during operation of the ECCS following a LOCA. The NaOH additive results in ~~the final pH being raised to greater than or equal to 7.0~~ post-LOCA sump pH of between 8.0 and 10.0 at the end of the NaOH injection period.

The Surveillance Requirements provided to ensure OPERABILITY of each component ensure that at a minimum, the assumptions used in the accident analyses are met and that subsystem OPERABILITY is maintained. Surveillance requirements for flow balance testing provide assurance that proper ECCS flows will be maintained in the event of a LOCA. Maintenance of proper flow resistance and pressure drop in the piping system to each injection point is necessary to: (1) prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration, (2) provide the proper flow split between injection points in accordance with the assumptions used in the ECCS-LOCA analyses, and (3) provide an acceptable level of total ECCS flow to all injection points equal to or above that assumed in the ECCS-LOCA analyses.

3/4.5.4 REFUELING WATER STORAGE TANK (RWST)

The OPERABILITY of the RWST as part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA. The limits on RWST minimum volume and boron concentration ensure that 1) sufficient water is available within containment to permit recirculation cooling flow to the core, and 2) the reactor will remain subcritical in the cold condition following mixing of the RWST and the RCS water volumes with all control rods inserted except for the most reactive control assembly. The limit on maximum boron concentration is to ensure that boron does not precipitable in the core following LOCA. The limit on RWST solution temperature is to ensure that the assumptions used in the LOCA analyses remain valid.

REFUELING WATER STORAGE TANK (Continued)

The water volume limits are specified relative to the limiting physical characteristics of the tanks and includes allowances for water not available because of discharge line location and other physical characteristics (RWST above the ECCS suction connection in lieu of the CVCS suction connection).

The limits on water volume and boron concentration of the RWST also ensure that ~~a pH value of between 7.4 and 8.0 for~~ the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The maximum RWST volume is not specified since analysis of pH limits and containment flooding post-LOCA considered RWST overflow conditions.

has a pH value between 8.0 and 10.0 at the end of the NaOH injection period.

3/4.6.1.7 CONTAINMENT VENTILATION SYSTEM

The 42-inch containment purge supply and exhaust isolation valves are required to be closed during plant operation since these valves have not beer demonstrated capable of closing during a LOCA or steam line break accident. Maintaining these valves closed during plant operations ensures that excessiv quantities of radioactive materials will not be released via the containment purge system.

The use of the containment purge lines is restricted to the 8-inch purge supply and exhaust isolation valves to ensure that the site boundary dose guidelines of 10 CFR Part 100 would not be exceeded in the event of a loss-of-coolant accident during purging operations.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the containment spray system ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the containment analyses.

The containment spray system and the containment cooling system are redundant to each other in providing post accident cooling of the containment atmosphere. However, the containment spray system also provides a mechanism for removing iodine from the containment atmosphere and therefore the time requirements for restoring an inoperable spray system to OPERABLE status have been maintained consistent with that assigned other inoperable ESF equipment.

3/4.6.2.2 IODINE REMOVAL SYSTEM

The OPERABILITY of the iodine removal system ensures that sufficient NaOH is added to the containment spray in the event of a LOCA. The limits on NaOH volume and concentration ensure ~~a pH value of between 8.0 and 10.0 for the~~ that the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride stress corrosion the effect of chloride and caustic stress corrosion on mechanical systems and components. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics. These assumptions are consistent with the iodine removal efficiency assumed in the accident analyses.

has a pH value between 8.0 and 10.0 at the end of the NaOH injection period.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% (1210 psig) of its design pressure of 1100 psig during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1974 Edition. The total relieving capacity for all valves on all of the steam lines is 15,473,628 lbs/hr which is 102.3 percent of the total secondary steam flow of 15,130,000 lbs/hr at 100% RATED THERMAL POWER. A minimum of 1 OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for removing decay heat.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Level-High channels. The reactor trip setpoint reductions are derived on the following bases:

For two loop, four pump operation

$$f \leq \frac{(2)(N)(\dot{\omega}_{sv})(h_g - h_{fw})}{(Q)} \quad \text{S.P.} = \left(\frac{q-N}{q}\right) \times 102.3$$

where: SEE INSERT "A" (NEXT PAGE)

f = maximum allowable fractional power level as a fraction of RATED THERMAL POWER ($f \leq 1.00$)

N = minimum number of operable main steam safety valves on any one generator

$\dot{\omega}_{sv}$ = steam flow capacity of each main steam safety valve at 1140 lb/in^{2}g (lbm/h)

Q = secondary heat transfer rate of both generators at RATED THERMAL POWER (Btu/h)

INSERT "A"

SP = reduced reactor trip setpoint in percent of Rated Thermal Power. This is a ratio of the available relieving capacity over the total steam flow at rated power.

9 = total number of secondary safety valves for one steam generator.

N = the number of inoperable secondary safety valves on the steam generator with the greater number of inoperable valves.

102.3 = the ratio of the total relieving capacity of all eighteen (18) secondary safety valves (15,473,628 lbs/hr at 1190 psia, maximum set pressure plus 3% accumulation) over the secondary steam flow at 100% Rated Thermal Load (15,130,000 lbs/hr).

SAFETY VALVES (Continued)

h_g = enthalpy of the saturated steam at the operating pressure of the steam generators (Btu/lbm)

h_{fw} = feedwater enthalpy at RATED THERMAL POWER, which is assumed to remain constant in order to yield a more conservative power level (Btu/lbm)

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the auxiliary feedwater system ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of off-site power.

Each electric driven auxiliary feedwater pump is capable of delivering a total feedwater flow of 700 gpm at a pressure of 1170 psig to the entrance of the steam generators. The steam driven auxiliary feedwater pump is capable of delivering a total feedwater flow of 700 gpm at a pressure of 1170 psig to the entrance of the steam generators. This capacity is sufficient to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the shutdown cooling system may be placed into operation.

3/4.7.1.3 CONDENSATE STORAGE TANKS

The OPERABILITY of the condensate storage tanks with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 24 hours with steam discharge to atmosphere with concurrent with total loss of off-site power. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

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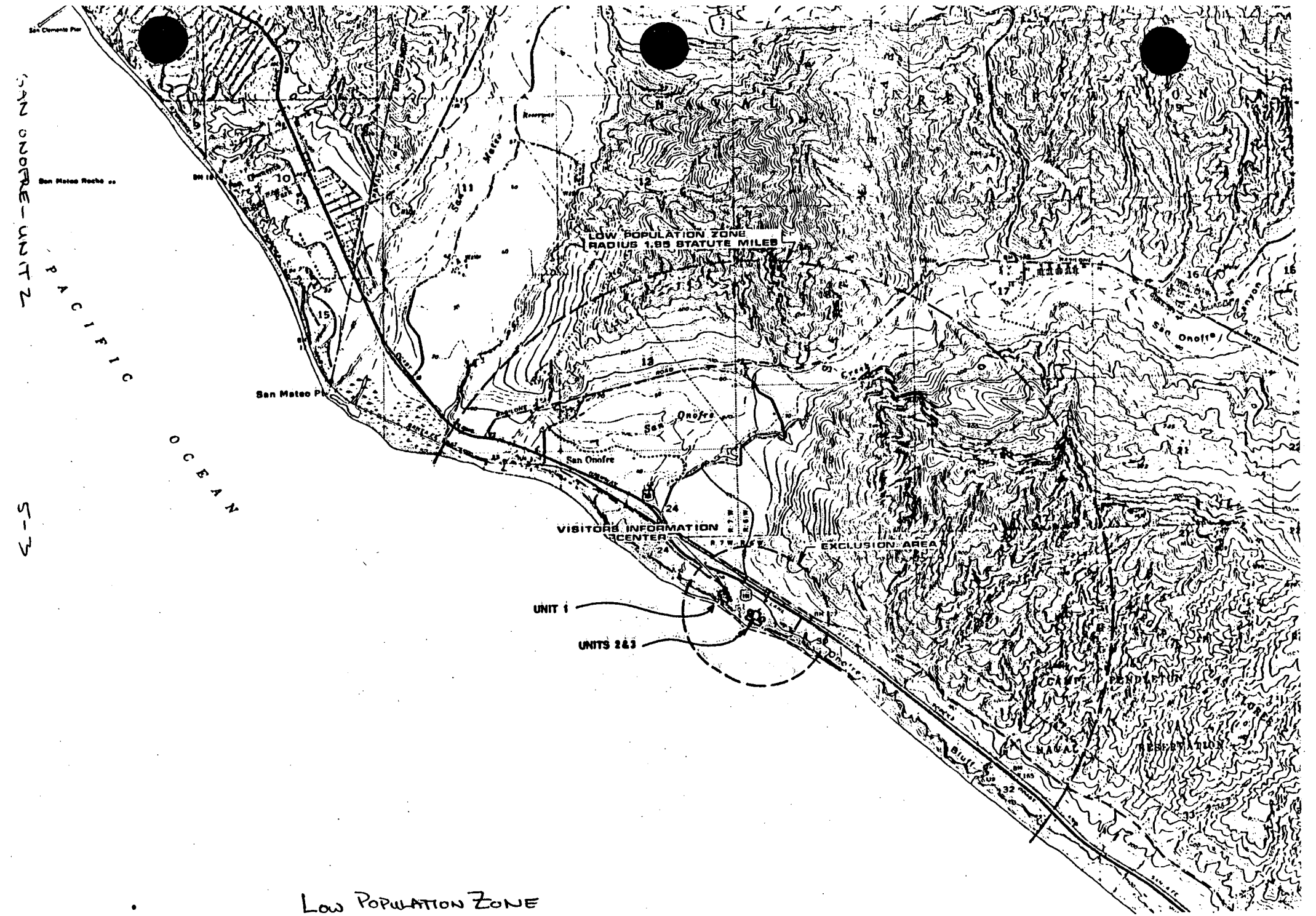
3/4.10.5 MINIMUM TEMPERATURES FOR CRITICALITY

This special test exception permits reactor criticality at low THERMAL POWER level with T_{avg} below 520°F during PHYSICS TESTS which provide data that can be used to verify the adequacy of the design codes for the first of a kind (3410 mwth) plant for reduced temperature conditions.

3/4.10.6 NATURAL CIRCULATION

This special test exception permits the reactor to be critical at low THERMAL POWER levels with no RCPs operating and with T_{avg} above and below 520°F during NATURAL CIRCULATION PHYSICS TESTS which provide data and operator training for plant performance in these conditions.

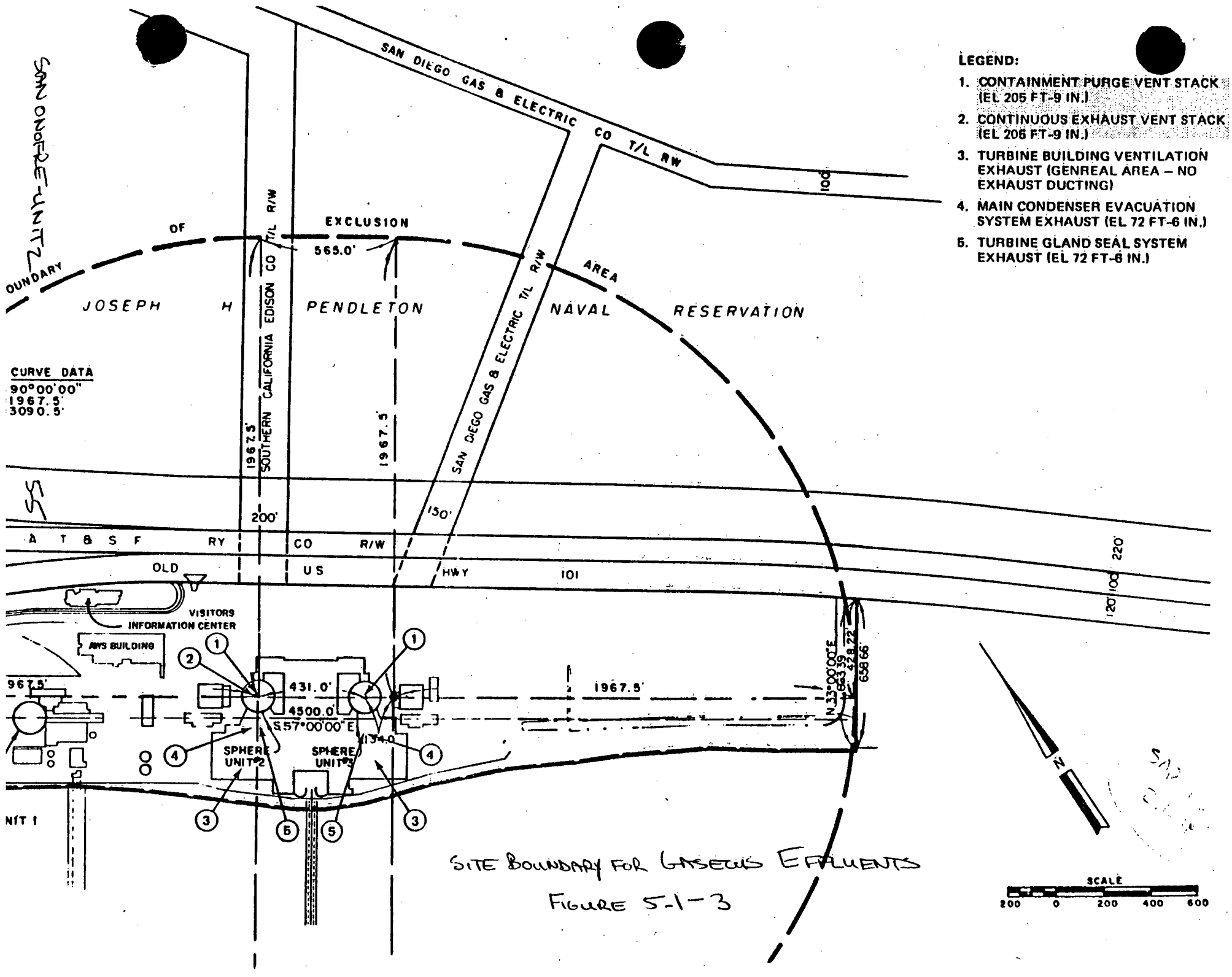


SAN ONOFRE-UNIT 2

5-3

Low Population Zone
Figure 5.1-2
San Onofre-Unit 2

079-11D-393
AUG

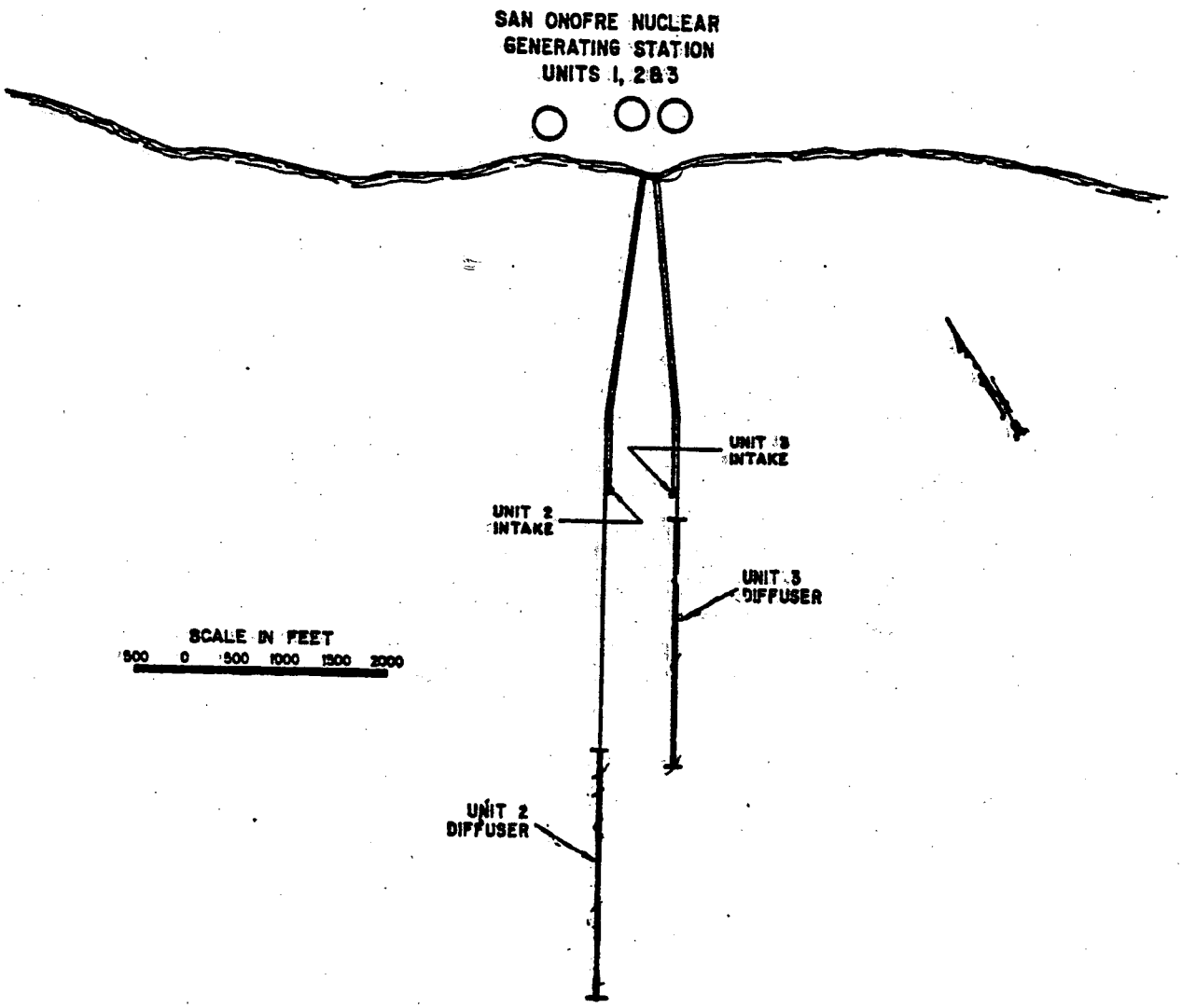


LEGEND:

1. CONTAINMENT PURGE VENT STACK (EL 205 FT-9 IN.)
2. CONTINUOUS EXHAUST VENT STACK (EL 206 FT-9 IN.)
3. TURBINE BUILDING VENTILATION EXHAUST (GENREAL AREA – NO EXHAUST DUCTING)
4. MAIN CONDENSER EVACUATION SYSTEM EXHAUST (EL 72 FT-6 IN.)
5. TURBINE GLAND SEAL SYSTEM EXHAUST (EL 72 FT-6 IN.)

SITE BOUNDARY FOR GASEOUS EFFLUENTS

FIGURE 5-1-3



SITE BOUNDARY FOR
LIQUID EFFLUENTS

FIGURE 5.1-4

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 217 fuel assemblies with each fuel assembly containing a maximum of 236 fuel rods clad with Zircaloy-4. Each fuel rod shall have a nominal active fuel length of 150 inches and contain a maximum total weight of 1807 grams uranium. The initial core loading shall have a maximum enrichment of ~~2.90~~ 2.91 weight percent U-235. Reload fuel shall be similar in physical design to the initial core loading and shall have a maximum enrichment of 3.7 weight percent U-235.

CONTROL ELEMENT ASSEMBLIES

5.3.2 The reactor core shall contain 83 full length and 8 part length control element assemblies.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR with allowance for normal degradation pursuant of the applicable Surveillance Requirements,

b. For a pressure of 2500 psia, and

c. For a temperature of 650°F, except for the pressurizer which is 700°F.

EDITORIAL COMMENTS

Comment No.	Specification	Comment
E-1	6.1.1	Change "Plant Manager" to "Station Manager" to conform to the Unit organization shown in Figure 6.2.2.
E-2	6.2.2.C (two places)	Change "chemical-radiation protection technician" to "health physics technician" to reflect a change in job title.
E-3	6.5.1.2	Change the titles of the following OSRC memebers to reflect revised Figure 6.2.2. a. "Assistant Station Manager, Operations" to "Manager, Operations". b. "Assistant Station Manager, Technical" to "Manager, Technical". c. "Plant Superintendent" to "Plant Superintendent S02". d. "Supervising Engineer I&C" to "Supervisor of I&C". e. "Health Physics Manager" to "Manager, Health Physics". f. "Chemistry Supervisor" to "Supervisor of Chemistry". g. "Assistant Station Manager, Maintenance" to "Manager, Maintenance". h. "Engineer" to "Supervising Engineer (NSSS, NSSS Support, Computer, or STAs)".
E-4	6.5.1.6.i	Delete the words "and implementating procedures and shall submit recommended changes to the NCB" since this is entirely redundant to Section 6.5.1.6.a along with 6.8.1.d and e, and Section 6.5.1.8.
E-5	6.5.1.6.k	Change "defective protection channels of process variable" to "defective ESFAS protection channels" to clarify which channels are under review here.
E-6	6.5.1.7	First, in paragraph "a" change "Plant Manager" to "Station Manager" and add the following sentence to the end:

Comment No.	Specification	Comment
		"An item which constitutes an unreviewed safety question or requires a change to the Technical Specifications shall not be approved by the OSRC without prior Commission Approval." Add the following clause to the end of paragraph "b": "or requires a change to the Technical Specifications". Second, reorder the paragraphs so that "a" becomes "b", and "b" becomes "a". The wording was revised to conform to 10CFR50.59. Paragraphs a. and b. were reordered to reflect the actual sequence of decisions (i.e., a safety determination is completed prior to approval or disapproval).
E-7	6.5.3.6	Change "NCS" to "NCB" Change "NSB" to "NSG" (typo's).
E-8	6.6	This section could be deleted since it is entirely redundant to 6.9, 6.5.1.6.f, 6.5.2.7.f and 6.5.2.10.
E-9	6.8.1	Change the publication date of R.6.1.33 Revision 2 to February 1978 (typo).
E-10	6.10.1.g 6.10.1.h 6.10.2.l 6.10.2.m	These retention requirements are unnecessary since the records are covered under 6.10.1.d.
E-11	6.10.1.e 6.10.2.j	Add "and records of reactor tests and experiments" Delete this requirements. These changes conform to 10CFR 50.59.
E-12	6.10.i 6.10.3	Delete 6.10.i and add 6.10.3 as follows: "6.10.3 Other records required by the Quality Assurance Manual shall be retained for a period of time in accordance with the guidance of ANSI N45.2.9-1974" This change is made to conform to R.G. 1.88 which endorses ANSI N45.2.9-1974.

INAPPROPRIATE SPECIFICATIONS

These comments concern proposed Technical Specifications which are inappropriate because they are premature or apply improper emphasis to lesser controls. Edison will, of course, meet previous committments in these areas, but we feel that a license condition is not appropriate for reasons stated below.

Comment No.	Specification	Comment
IS-1	6.1.2	The requirement for a management directive signed by the Vice President of Nuclear Operations describing the Control Room command function is inappropriate as a Technical Specification since: a. This item originated from NUREG-0578 Section 2.2.1.a and NUREG 0737 Enclosure 1 indicates no Technical Specification requirement is necessary. b. The licensing emphasis on this annual directive is greatly out of proportion to other administrative programs such as operator retraining and qualification, emergency planning, independent safety reviews, etc.
IS-2	6.2.3	A Technical Specification requirement for an Independent Safety Engineering Group (ISEG) is inappropriate since discussion of ISEG has been labled premature and removed from R.G. 1.33 draft revision 3 dated July 1, 1981. Removal of ISEG requirements would allow us more flexibility to meet and improve our agreements with the NRC in this area without changing the licensing basis of the plant.
IS-3	6.4.1	Reference to Enclosure 1 to the March 28, 1980 letter from H.R. Denton is inappropriate since the requirements for Reactor Operator Training are still in the formative stage. Discussions between licensees, NRC, INPO and many other organizations alternatives are in progress. At this point it is premature to establish these licensing conditions for Operator Training, especially when some of the criteria may actually be counter-productive. For example, it has been pointed out that Section A.2.d which requires all training instructors to complete an SRO exam eliminates the use of individuals such as the system designer to teach the system he designed.

COMMENTS ON SECTION 6.0, "ADMINISTRATIVE CONTROLS"

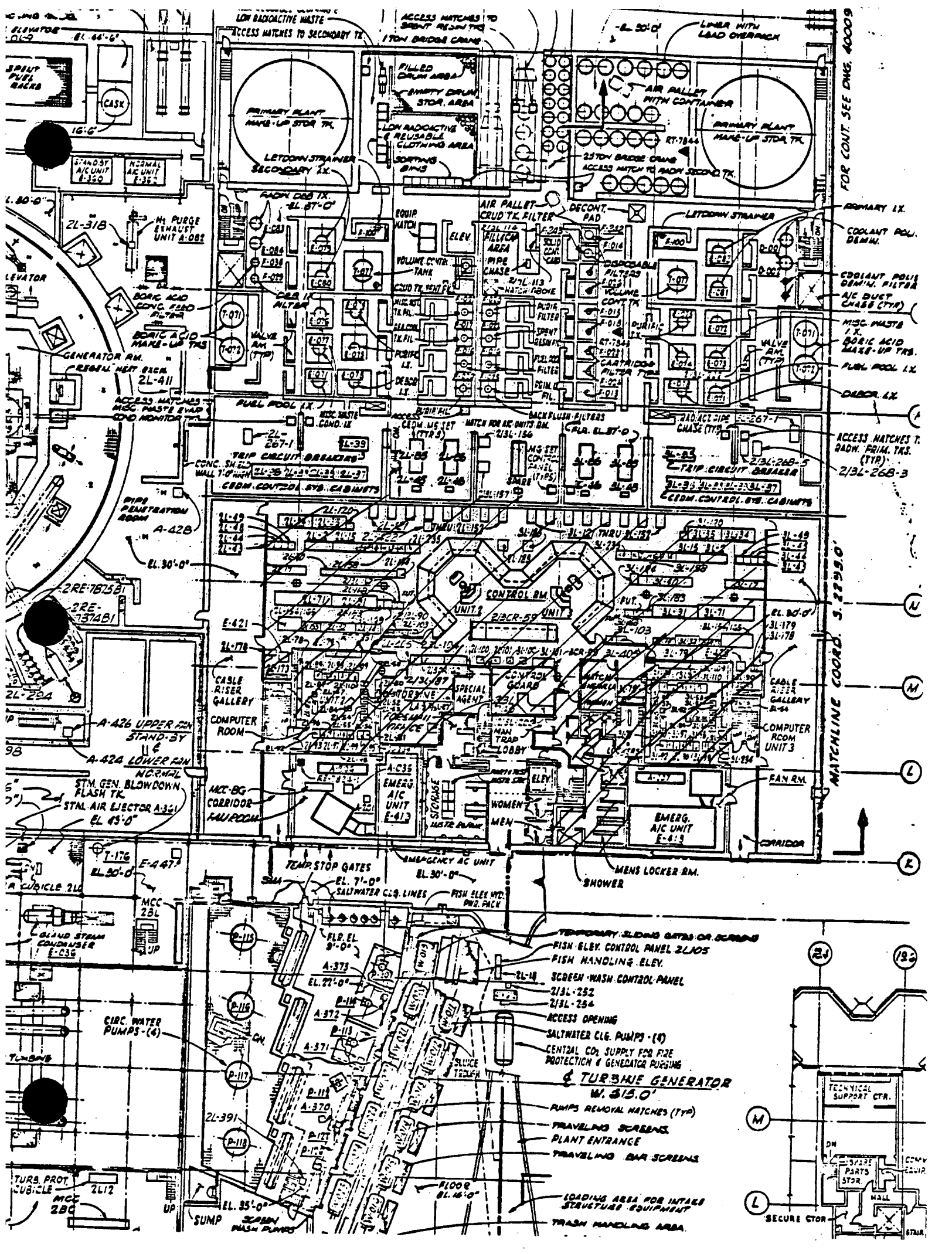
TECHNICAL COMMENTS

Comment No.	Specification	Comment
T-1	6.2.2.6	Change "Control Room" to "Control Room Area," as shown on the attached drawing T-1-2, to allow the SRO to work in an area outside the centralized control panels designated as the Control Room. This additional area allows the SRO: a. to investigate problems and monitor operation of equipment with controls or indication outisde the "double horseshoe" area. These panels include radiation monitoring system indication, HVAC system controls, seismic event recorders, meteorological data, and other important instruments. b. Access to the Watch Engineer office where additional reference material is available as well as phone connections to the NRC and other outside agencies. This office also provides space for discussion of technical problems without adding to the congestion and noise level in the Control Room. c. To discuss security, chemistry, and plant monitoring problems with the cognizant foreman as analysis and investigation are performed. d. To get a cup of coffee or go to the bathroom without disrupting the activities of the Shift Supervisor while making a plant tour or investigating a potential problem area. The Control Room Area is within the Control Room emergency ventilation envelope, inside the area where access in controlled by the man trap, and the public address system can be clearly heard throughout all spaces.
T-2	6.2.3.2	Change to read "The ISEG shall be composed of the equivilant of 5 full time engineers located onsite.

Comment No.	Specification	Comment
		Shift Technical Advisors may be used to fulfill this requirement". This change allows use of engineers other than STA's when additional or specialized expertise is need.
T-3	6.5.1.6.d	With regard to facility changes, we would like NRC agreement that the present wording allows the Station Manager, Technical (or equivilant level) to screen facility changes and approve those changes considered minor prior to OSRC review. These changes will subsequently be reviewed by OSRC at the next monthly meeting and the OSRC will concur with both the decision that the change was appropriate for approval prior to OSRC review and that the conclusions in the safety evaluation were correct. In all cases the safety evaluation required by 10CFR50.59 will be performed prior to approval of the change. This process is desired to resolve our concerns and NRC I&E concerns on the workload of the OSRC and their ability to personally conduct all reviews without having too great an affect on their line management duties. Table T-3-1 summarizes OSRC activities for Unit 1 in 1980. With Units 2&3 in operation, the number of reviews is expected to triple. It is obvious the OSRC will not be able to perform all the reviews in a committee meeting. The above program allows upper station management to screen some items for prior OSRC review and also provides for reprots to the committee so that it can verify the adequacy of the screening process as a means of carrying out.
T-4	6.5.2	As described in the FSAR and SER, the Nuclear Safety Group is a staff organization, not a standing committee. Thus the following changes are needed. "6.5.2.2 The NSG shall consist of a supervisor and at least three staff specialists, who collectively shall be knowledgeable in the disciplines of 6.5.2.1. The NSG may, if necessary, use specialists from other technical organizations to augment their expectise in the disciplines of 6.5.2.1".

Comment No.	Specification	Comment
		"6.5.2.3 Alternates; 6.5.2.5 Meeting Frequency; 6.5.2.6 Quorum" - delete these sections. "6.5.2.10 Records of NSG activities shall be prepared and maintained. A summary shall be distributed each calendar month to the Station Manager and NCB members".
T-5	6.5.2.7	Delete the requirement for NSG review of safety evaluations for changes to procedures that do not involve an unreviewed safety question. It is anticipated that about 6,000 Station procedures will be written for operation of Units 1, 2, and 3. Review and approval of these procedures is described in Section 6.8 NSG Review of all Procedure changes be a heavy burden and would place an improper emphasis on this area.
T-6	6.5.3.2	Change the NCB membership as follows: a. Change the "Vice President-Engineering and Construction" to "Manager of Engineering Designs". This change is requested since the Manager, Engineering Design is more familiar with the design criteria and plant operation. b. Delete the "Vice President-Advanced Engineering". This change is requested since the Manager, Quality Assurance is able to evaluate technical problems under the cognizance of Advanced Engineering and advise the Vice President.
T-7	6.8.2	Revise present wording to read as follows: Subject to a, b, and c below, the initial issue and any subsequent change to the intent of each procedure described in Specification 6.8.1 above shall be reviewed by at least two memebers of Station Supervision knowledgeable in the areas affected by the procedure and shall be approved by the cognizant manager prior to implementation, and shall be forwarded by OSRC for review and concurrence.

Comment No.	Specification	Comment
		a. Procedures and changes to the intent thay may affect the operational status of the plant systems or equipment shall also be reviewed by a senior Reactor Operator if neither of the two members of Station Supervisors is so qualified. b. Revisions that do not change the intent of the approved procedure shall, as a minimum, be approved by two members of the plant staff knowledgeable in the areas affected by the procedure. At least one of these shall be a member of OSRC knowledgeable in the areas affected. c. Procedure revisions shall be reviewed at periodic intervals as set forth in administrative procedures. These sections were revised to resolve concerns on OSRC workload as discussed in Comment T-3. The changes are based on recent drafts of ANS 3.1 and experience gained from operation of San Onofre Unit 1.


LOW RADIOACTIVE WASTE ACCESS HATCHES TO SECONDARY TK.
ACCESS HATCHES TO SPENT RESIN TKS.
100 TON BRIDGE CRANE
EL. 50'-0"
LINER WITH LEAD OVERPACK
FOR CONT. SEE DWG. 40009
SPENT FUEL RACKS
CASK
FILLED DRUM AREA
EMPTY DRUM STOR. AREA
LOW RADIOACTIVE & REUSABLE CLOTHING AREA
SORTING BINS
AIR PALLET WITH CONTAINER
PRIMARY PLANT MAKE-UP STOR TK.
LETDOWN STRAINER SECONDARY TK.
25 TON BRIDGE CRANE
ACCESS HATCH TO RADW. SECOND TK.
STAND BY A/C UNIT E-360
NORMAL A/C UNIT E-362
RADON DGS TK. EL. 87'-0"
EQUIP HATCH
ELEV.
AIR PALLET CRUD TK. FILTER
DECONT. PAD
LETDOWN STRAINER
PRIMARY TK.
2L-318
M1 PURGE EXHAUST UNIT A-082
VOLUME CONTR. TANK
FILTER AREA
PIPE CHASE
2/3L-113 HATCH ABOVE
DISPOSABLE FILTERS
VOLUME CONT. TK.
COOLANT POLI. DEMIN.
COOLANT POLI. DEMIN. FILTER
A/C DUCT CHASE (TYP.)
MISC. WASTE T.K.
BORIC ACID MAKE-UP TKS.
FUEL POOL T.K.
DEBOR. T.K.
BORIC ACID CONC. FEED FILTER
BORIC ACID MAKE-UP TKS
CRA T.K. FILTER
VALVE RM. (TYP.)
GENERATOR RM.
REGEN. HEAT EXCH. 2L-411
ACCESS HATCHES MISC. WASTE EVAP. COND. MONITOR TK.
FUEL POOL T.K.
BACK FLUSH FILTERS
2AD ACT. PIPE CHASE (TYP.)
2L-267-1
ACCESS HATCHES T. RADW. PRIM. TKS. (TYP.)
2/3L-268-3
TRIP CIRCUIT BREAKERS
CONC. SH. EL. WALL T.O. @ EL. 30'-0"
CEDM CONTROL SYS. CABINETS
PIPE PENETRATION ROOM A-428
EL. 30'-0"
2RE-7825B1
2RE-7874B1
2L-294
E-421
2L-178
CABLE RISER GALLERY
COMPUTER ROOM
A-426 UPPER FAN STAND-BY
A-424 LOWER FAN NORMAL
STM. GEN. BLOWDOWN FLASH TK.
STM. AIR EJECTOR A-361
EL. 45'-0"
MCC-BG CORRIDOR
FAN ROOM
A-C35 EMERG. A/C UNIT E-413
STORAGE
WASTE PUMP
CONTROL RM UNIT 2
2/3CR-59
SPECIAL AGENT
CONTROL GEARS
MATCH LINE EL. 22'-0"
MAN TRAP LOBBY
WOMEN
MEN
ELEV.
CABLE RISER GALLERY
COMPUTER ROOM UNIT 3
FAN RM.
EMERG. A/C UNIT E-413
CORRIDOR
MATCHLINE COORD. S. 2299.0'
EMERGENCY AC UNIT
EL. 30'-0"
MENS LOCKER RM.
SHOWER
T-176
EL. 30'-0"
E-447
TEMP. STOP GATES
SEAL
EL. 7'-0"
SALTWATER C.W. LINES
FISH ELEV. MTD. PWR. PACK
MCC 2BL
GLAND STEAM CONDENSER E-036
P-115
FLR. EL. 9'-0"
TEMPORARY SLIDING GATES OR SCREENS
FISH ELEV. CONTROL PANEL 2L105
FISH HANDLING ELEV.
A-373
EL. 22'-0"
2L-18
SCREEN WASH CONTROL PANEL
2/3L-252
2/3L-254
P-116
P-114
A-372
ACCESS OPENING
SALTWATER C.W. PUMPS - (4)
CENTRAL CO2 SUPPLY FOR FIRE PROTECTION & GENERATOR PURGING
CIRC. WATER PUMPS - (4)
P-113
A-371
SLUICE TROUGH
TURBINE
P-117
℄ TURBINE GENERATOR W. 315.0'
P-111
A-370
PUMPS REMOVAL HATCHES (TYP.)
TRAVELING SCREENS
2L-391
PLANT ENTRANCE
P-118
TRAVELING BAR SCREENS
P-112
FLOOR EL. 16'-0"
LOADING AREA FOR INTAKE STRUCTURE EQUIPMENT
TURB. PROT. CUBICLE
2L12
MCC 2BC
EL. 35'-0"
SUMP
SCREEN WASH PUMPS
TRASH HANDLING AREA
TECHNICAL SUPPORT CTR.
SPARE PARTS STOR.
SECURE STOR.
MALL
STAIR

OSRC ACTIVITIES 1980

OSRC MTG	New Form or Procedure	Existing Proc. or Form Review or Revision	Design Changes	License Amend's	Incident Report Discussion	NARC/OSRC Action Item Status Chg.	NRC Correspond. Review	Internal Communication Review	CAR/NCR Responses	Monthly Review of O&M	Other
Jan. 7	14	7									
Jan. 11					1						
Jan. 16		1		1	1						
Jan. 18	7	32			9	5	13	4	11	1	
Jan. 25	4	30									
Jan. 28	2	4	2	3							
Jan. 29	3	2		1							
Feb. 1	8	13									
Feb. 5	2	3									
Feb. 6	2	6	4								
Feb. 8	8	9									
Feb. 10											1
Feb. 13	3	10									
Feb. 19					1						
Feb. 15	2	5	1								
Feb. 25	7	11	2		4	7	8	13	8	1	
Feb. 27	1	3									
Mar. 5	2	21									1
Mar. 6					1						
Mar. 7		1	1								
Mar. 11		11									
Mar. 14	1										
Mar. 17					1						
Mar. 18	2	18	1		4	3	2	6	1	1	
Mar. 20	1	2	3	3							
Mar. 21					1						

OSRC ACTIVITIES 1980

OSRC MTG	New Form or Procedure	Existing Proc. or Form Review or Revision	Design Changes	License Amend's	Incident Report Discussion	NARC/OSRC Action Item Status Chg.	NRC Correspond. Review	Internal Communication Review	CAR/NCR Responses	Monthly Review of O&M	Other
Mar. 24					2						
Mar. 25		15		2							
Mar. 26			6								
Apr. 4	18	34			1						
Apr. 9	2	8	4								1
Apr. 10	1										
Apr. 11	2										
Apr. 12	1										
Apr. 14	6	7									
Apr. 16	2	7									
Apr. 19	5	4									
Apr. 21		1			1						
Apr. 22	7	18			7	13	6	8	7	1	
Apr. 22	5	8									
Apr. 28	5	8			1						
May 1	5	13	6								
May 4					1						
May 5	7	25									
May 6		9			2						
May 8	12	10	5								
May 10	2	3									
May 11		2									1
May 12	1										
May 13	5	4	1								
May 15	2	2									
May 16	5	4									

OSRC ACTIVITIES 1980

OSRC MTG	New Form or Procedure	Existing Proc. or Form Review or Revision	Design Changes	License Amend's	Incident Report Discussion	NARC/OSRC Action Item Status Chg.	NRC Correspond. Review	Internal Communication Review	CAR/NCR Responses	Monthly Review of O&M	Other
May 17	1										
May 19	1	1									
May 21	1	14			2	4	6	2		1	
May 22	7	11									1
May 23	3	6	1								1
May 29	6	5						1			1
June 2	3	8									
June 3	2	7									
June 4	1	1			1						
June 10	1	10	1								
June 12	1	8									
June 19	3	16									
June 24	3	18	1	3	3	97	21	6	2	1	
June 26	1	20									
June 27	5	10			1						1
June 30		5									
July 2	1	11									
July 7	3	4	1								
July 14	2	27			1						
July 16		8									
July 22		27		1	4	52	12	8	6	1	1
July 28	2	27	2								
July 29		2		1							
Aug. 5	32	60	4								1
Aug. 11	1	8									
Aug. 18		15	1	3							

OSRC ACTIVITIES 1980

OSRC MTG	New Form or Procedure	Existing Proc. or Form Review or Revision	Design Changes	License Amend's	Incident Report Discussion	NARC/OSRC Action Item Status Chg.	NRC Correspond. Review	Internal Communication Review	CAR/NCR Responses	Monthly Review of O&M	Other
Aug. 19	3	5			1						
Aug. 21		6			3	43	9	13	13	1	1
Aug. 25		3									
Aug. 26		2	1								
Aug. 27	3	2									
Aug. 28		7	1								
Aug. 29	2		1								
Aug. 31					1						
Sept. 5		15									1
Sept. 9	3	5			1						1
Sept. 11	1										
Sept. 12		14	1								
Sept. 13	5										1
Sept. 14		1					2				1
Sept. 15		2				1		2			
Sept. 19		6									
Sept. 22			1		1						
Sept. 25		7			1			2			
Sept. 29	1	22	3	1	3	39	3		20	1	
Oct. 3	1	24	1								
Oct. 7		9									1
Oct. 9	1										
Oct. 10	4	17	4								
Oct. 15	1	22									
Oct. 18	3	3									

OSRC ACTIVITIES 1980

OSRC MTG	New Form or Procedure	Existing Proc. or Form Review or Revision	Design Changes	License Amend's	Incident Report Discussion	NARC/OSRC Action Item Status Chg.	NRC Correspond. Review	Internal Communication Review	CAR/NCR Responses	Monthly Review of O&M	Other
Oct. 20			5	1							
Oct. 22	1	17	1		1	22	8	7		1	
Oct. 24			3								
Oct. 27		17	5								
Oct. 31	1	6	5	1							
Nov. 1	1										
Nov. 3			2								
Nov. 5		9									
Nov. 7		6	1					1			2
Nov. 9	3	7	1								
Nov. 14	2	2						1			
Nov. 18	1	14	2								
Nov. 20	4	7			4	57	9	3		1	
Nov. 26	2	16	1								
Dec. 1	1	2									
Dec. 4	1	4									
Dec. 6		1						1			
Dec. 8	2	22	2					2			
Dec. 12	3	43	2								
Dec. 17	2	5			3	50	6			1	
Dec. 19	7	6									
Dec. 23	1	6	1	1							
Totals	302	1073	91	21	69	393	105	80	58	12	18

SUM TOTALS 2,222

6.1 RESPONSIBILITY

E-1

6.1.1 The ~~Plant~~ Station Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Watch Engineer (or during his absence from the Control Room, a designated individual) shall be responsible for the Control Room command function. ~~A management directive to this effect, signed by the Vice-President of Nuclear Operations shall be reissued to all station personnel on an annual basis.~~

IS-1

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for unit management and technical support shall be as shown in Figure 6.2-1.

UNIT STAFF

6.2.2 The Unit organization shall be as shown in Figure 6.2-2 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1.

b. At least one licensed Reactor Operator shall be in the Control Room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, 3 or 4, at least one licensed Senior Reactor Operator shall be in the Control Room/area. T-1

E-2

c. A ~~chemical-radiation protection~~ health Physics technician# shall be on site when fuel is in the reactor.

d. All CORE ALTERATIONS shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

e. A site Fire Brigade of at least 5 members shall be maintained onsite at all times.# The Fire Brigade shall not include the Watch Engineer and the (2) other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency.

E-2

#The ~~radiation protection~~ health Physics technician and Fire Brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence provided immediate action is taken to fill the required positions.

6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports and other sources of plant design and operating experience information which may indicate areas for improving plant safety.

delete IS-2

COMPOSITION

6.2.3.2 The ISEG shall be composed of the equivilant of five full time engineers located on-site. at least five [redacted] Shift Technical Advisors, may be used to fulfill this requirement. T-2

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of plant activities to provide independent verification* that these activities are performed correctly and that human errors are reduced as much as practical.

AUTHORITY

6.2.3.4 The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities or other means of improving plant safety to the Supervisor, Nuclear Safety Group.

6.2.4 SHIFT TECHNICAL ADVISOR

The Shift Technical Advisor shall provide technical support to the Watch Engineer in the areas of thermal hydraulics, reactor engineering and plant analysis with regard to the safe operation of the unit.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions.

*Not responsible for sign-off function.

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6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Manager, Nuclear Training and shall meet or exceed the requirements and recommendations of Sections 5.5 of ANSI N18.1-1971 ~~and Appendix "A" of 10 CFR Part 55 and the supplemental requirements specified in Section A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees~~, and shall include familiarization with relevant industry operational experience ~~identified by the ISEG~~.

IS-3

IS-2

6.5 REVIEW AND AUDIT

6.5.1 ONSITE REVIEW COMMITTEE (OSRC)

FUNCTION

6.5.1.1 The Onsite Review Committee shall function to advise the Station Manager on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The Onsite Review Committee shall be composed of the:

Chairman:		Station Manager ~~—~~ Deputy Station Manager
Member:		~~Assistant Station~~ Manager, Operations
Member:		~~Assistant Station~~ Manager, Technical
Member:		Plant Superintendent SO2
Member:	Supervisor of	~~Supervising Engineer~~, I&C
Member:		~~Health Physics~~ Manager, Health Physics
Member:		~~Chemistry~~ Supervisor of Chemistry
Member:		~~Assistant Station~~ Manager, Maintenance
Member:	Supervising	Engineer (NSSS, NSSS Support, Computer, or STA's)
Member:		San Diego Gas & Electric Representative

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the OSRC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in OSRC activities at any one time.

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MEETING FREQUENCY

6.5.1.4 The OSRC shall meet at least once per calendar month and as convened by the OSRC Chairman or his designated alternate.

QUORUM

6.5.1.5 The minimum quorum of the OSRC necessary for the performance of the OSRC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and four members including alternates.

RESPONSIBILITIES

6.5.1.6 The Onsite Review Committee shall be responsible for:

a. Review of 1) all procedures required by Specification 6.8 and changes thereto, 2) all programs required by Specification 6.8 and changes thereto, 3) any other proposed procedures or changes thereto as determined by the Station Manager to affect nuclear safety.

b. Review of all proposed tests and experiments that affect nuclear safety.

c. Review of all proposed changes to Appendix "A" Technical Specifications.

(T-3) d. Review of all proposed changes or modifications to unit systems or equipment that affect nuclear safety.

e. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Nuclear Control Board (NCB).

f. Review of events requiring 24-hour written notification to the Commission.

g. Review of unit operations to detect potential nuclear safety hazards.

h. Performance of special reviews, investigations or analyses and reports thereon as requested by the Station Manager or the NCB.

i. Review of the Security Plan ~~and implementing procedures and shall submit recommended changes to the NCB.~~ (E-4)

j. Review of the Emergency Plan ~~and implementing procedures and shall submit recommended changes to the NCB.~~

k. Review and documentation of judgment concerning prolonged operation in bypass, channel trip, and/or repair of defective protection channels ~~of process variables~~ placed in bypass since the last OSRC meeting.

l. Review of modifications to the Core Protection Calculator (CPC) Addressable Constants as required by Specification 2.2.2. (ESFAS) (E-5)

AUTHORITY

6.5.1.7 The Onsite Review Committee (OSRC) shall:

a. Recommend in writing to the ~~Plant~~ Station Manager approval or disapproval of items considered under 6.5.1.6(a) through (d) above.

b. Render determinations in writing with regard to whether or not each item considered under 6.5.1.6(a) through (e) above constitutes an unreviewed safety question, or requires a change to the Technical Specifications.

c. Provide written notification within 24 hours to the Nuclear Control Board of disagreement between the OSRC and the Station Manager; however, the Station Manager shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above.

An item which constitutes an unreviewed safety question or requires a change to the Technical Specifications shall not be approved by the OSRC without prior Commission approval.

E-6

RECORDS

6.5.1.8 The Onsite Review Committee shall maintain written minutes of each OSRC meeting that, at a minimum, document the results of all OSRC activities performed under the responsibility and authority provisions of these technical specifications. Copies shall be provided to the Nuclear Control Board.

6.5.2 NUCLEAR SAFETY GROUP (NSG)

FUNCTION

6.5.2.1 The Nuclear Safety Group shall function to provide independent review and audit of designated activities in the areas of:

a. nuclear power plant operations

b. nuclear engineering

c. chemistry and radiochemistry

d. metallurgy

e. instrumentation and control

f. radiological safety

g. mechanical and electrical engineering

h. quality assurance practices

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COMPOSITION

The NSG Supervisor and at least three staff specialists, who collectively shall be knowledgeable in the disciplines of 6.5.2.1. The NSG may, if necessary, use specialists from other technical organizations to augment their expert. in the disciplines of 6.5.2.1.

6.5.2.2 ~~NSRC~~ shall consist of a ~~Chairman and from three to ten other members appointed by the Nuclear Control Board. Appointments shall be for an indefinite period and may include outside consultants, as well as representatives from other departments within Southern California Edison. No more than a minority of the members of the NSG may be from the nuclear station staff. Chairmanship shall be designated by the Nuclear Control Board.~~

T-4

~~The NSG as a whole shall have a minimum of 5 years experience in the disciplines of 6.5.2.1 a. through h.. Each NSG member shall hold a Bachelor's degree or equivalent plus 5 years experience in one or more of the disciplines of 6.5.2.1 a. through h..~~ Each member of the NSG staff shall have a Bachelors Degree in engineering or Science or equivalent and a minimum of five years of experience in his field.

ALTERNATES

delete

6.5.2.3 All alternate members shall be appointed in writing by the NSG Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in NSG activities at any one time.

T-4

CONSULTANTS

6.5.2.4 Consultants shall be utilized as determined by the NSG Chairman to provide expert advice to the NSG.

MEETING FREQUENCY

6.5.2.5 The NSG shall meet at least once per calendar quarter during the initial year of unit operation following fuel loading and at least once per six months thereafter.

T-4

QUORUM

6.5.2.6 The minimum quorum of the NSG necessary for the performance of the NSG review and audit functions of these Technical Specifications shall consist of the Director or his designated alternate and at least 3 NSG members including alternates. No more than a minority of the quorum shall have line responsibility for operation of the unit.

delete

REVIEW

6.5.2.7 The NSG shall review:

T-5

a. The safety evaluations for 1) changes to ~~procedures~~, equipment or systems and 2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question.

b. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

c. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

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i. An independent fire protection and loss prevention inspection and audit shall be performed annually utilizing either qualified offsite licensee personnel or an outside fire protection firm.

j. An inspection and audit of the fire protection and loss prevention program shall be performed by an outside qualified fire consultant at intervals no greater than 3 years.

AUTHORITY

6.5.2.9 The NSG shall report to and advise the Manager, Nuclear Engineering and Safety on those areas of responsibility specified in Sections 6.5.2.7 and 6.5.2.8.

RECORDS

6.5.2.10 Records of NSG activities shall be prepared, approved and ~~distributed as indicated below:~~ A summary shall be distributed each calendar month to the Station Manager and NCB members.

~~a. Minutes of each NSG meeting shall be prepared, approved and forwarded to the Nuclear Control Board within 14 days following each meeting.~~

~~b. Reports of reviews encompassed by Section 6.5.2.7 above, shall be prepared, approved and forwarded to the Nuclear Control Board within 14 days following completion of the review.~~

~~c. Audit reports encompassed by Section 6.5.2.8 above, shall be forwarded to the Nuclear Control Board and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization.~~

T-4

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6.5.3 NUCLEAR CONTROL BOARD

FUNCTION

6.5.3.1 The Nuclear Control Board (NCB) shall function to provide company direction in the resolution of significant safety issues.

COMPOSITION

6.5.3.2 The NCB shall be composed of the following SCE employees:

Chairman:	Vice President - Nuclear Engineering and Operations
Member: (T-6)	~~Vice-President - Engineering and Construction~~ Manager of Engineering Design
Member:	~~Vice-President - Advanced Engineering~~
Member:	Manager - Nuclear Engineering, Licensing, and Safety
Member:	Manager - Nuclear Operations
Member:	Manager - Nuclear Engineering and Safety
Member:	Manager, Quality Assurance

ALTERNATES

6.5.3.3 All alternate members shall be appointed in writing by the NCB Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in NCB activities at any one time.

MEETING FREQUENCY

6.5.3.4 The NCB shall meet at least once per calendar quarter during the initial year of unit operation following fuel loading and at least once per six months thereafter.

QUORUM

6.5.3.5 A quorum of the NCB shall consist of the Chairman or his designated alternate and three members including alternates.

RESPONSIBILITIES

6.5.3.6 With respect to these Technical Specifications, the NCB shall oversee the activities of the NSG and OSRC and maintain management control for nuclear safety issues. (E-7)

6.6 REPORTABLE OCCURRENCE ACTION delete (E-8)

6.6.1 The following actions shall be taken for REPORTABLE OCCURRENCES:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Specification 6.9.

b. Each REPORTABLE OCCURRENCE requiring 24 hour notification to the Commission shall be reviewed by the OSRC and submitted to the NSG and the Nuclear Control Board.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within one hour. The Manager of Nuclear Operations and the NCB Chairman shall be notified within 24 hours.

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the OSRC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence.

c. The Safety Limit Violation Report shall be submitted to the Commission, and the Nuclear Control Board within 14 days of the violation.

d. Critical operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978. (E-9)

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

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g. PROCESS CONTROL PROGRAM implementation.

h. OFFSITE DOSE CALCULATION MANUAL implementation.

i. Quality Assurance Program for effluent and environmental monitoring, using the guidance in Regulatory Guide 4.15, December 1977.

6.8.2 Each procedure of 6.8.1 above, and changes thereto, shall be reviewed by the OSRC and approved by the Station Manager prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 Revisions to procedures of 6.8.1 above which do not involve a deviation from the Technical Specification or an unreviewed safety question may be made provided:

a. Revisions which do not change the intent of the approved procedures, shall as a minimum be approved by two members of the plant staff knowledgeable in the areas affected by the procedure. At least one of these shall be a member of the OSRC (or an alternate).

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b. Revisions which change the intent of the approved procedure, shall as a minimum be approved by the OSRC.

c. Revisions to procedures which may affect the operational status of plant systems or equipment shall be approved by the OSRC and a Senior Reactor Operator.

6.8.4 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the high pressure safety injection recirculation, the shutdown cooling system, the reactor coolant sampling system (post-accident sampling piping only), the containment spray system, the radioactive waste gas system (post-accident sampling return piping only) and the liquid radwaste system (post-accident sampling return piping only). The program shall include the following:

(i) Preventive maintenance and periodic visual inspection requirements, and

(ii) Integrated leak test requirements for each system at refueling cycle intervals or less.

Subject to a, b, and c below, the initial issue and any subsequent change to the intent of each procedure described in Specifications 6.8.1 above shall be reviewed by at least ~~the~~ two members of Station Supervision knowledgeable in the areas affected by the procedure and shall be approved by the cognizant manager prior to implementation, and shall be forwared by OSRC for review and concurrence.

a. Procedures and changes to the intent that may affect the operational status of plant systems or equipment shall also be reviewed by a senior reactor operator if neither of the two members of Station Supervision is so qualified.

b. Revisions that do not change the intent of the approved procedure shall, as a minimum, be approved by two member of the plant staff knowledgeable in the areas affected by the procedure. At least one of these shall be a member of OSRC knowledgeable in the areas affected.

c. Procedure revisions shall be reviewed at periodic intervals as set forth in administrative procedures.

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE OCCURRENCES submitted to the Commission.

d. Records of surveillance activities; inspections and calibrations required by these Technical Specifications.

e. Records of changes made to the procedures required by Specification 6.8.1, *and records of reactor tests and experiments* (E-11)

f. Records of radioactive shipments.

~~g. Records of sealed source and fission detector leak tests and results.~~ (E-10)

~~h. Records of annual physical inventory of all sealed source material of record.~~

6.10.2 The following records shall be retained for the duration of the Unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of radiation exposure for all individuals entering radiation control areas.

d. Records of gaseous and liquid radioactive material released to the environs.

e. Records of transient or operational cycles for those unit components identified in Table 5.7-1.

(E-11) ~~f. Records of reactor tests and experiments.~~

g. Records of training and qualification for current members of the unit staff.

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h. Records of in-service inspections performed pursuant to these Technical Specifications. (E-12)

~~i. Records of Quality Assurance activities required by the QA Manual.~~

~~j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.~~ (E-11)

k. Records of meetings of the OSRC and the NSG.

~~l. Records of the service lives of all snubbers listed in Tables 3.7-4a and 3.7-4b including the date at which the service life commences and associated installation and maintenance records.~~ (E-10)

~~m. Records of secondary water sampling and water quality.~~

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

6.12.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.203(c)(2) of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP)*. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate level in the area has been established and personnel have been made knowledgeable of them.

E 6.10.3 Other records required by the Quality Assurance Manual shall be retained for a period of time in accordance with the guidance of ANSI N45.2.9-1974

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c. An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the facility Health Physicist in the Radiation Work Permit.

6.12.2 In addition to the requirements of 6.12.1, areas accessible to personnel with radiation levels such that a major portion of the body could receive in one hour a dose greater than 1000 mrem shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the ~~Shift Foreman~~ on duty and/or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved ~~RWP~~ which shall specify the dose rate levels in the immediate work area and the maximum allowable stay time for individuals in that area. For individual areas accessible to personnel with radiation levels such that a major portion of the body could receive in one hour a dose in excess of 1000 mrem** that are located within large areas, such as PWR containment, where no enclosure exists for purposes of locking, and no enclosure can be reasonably constructed around the individual areas, then that area shall be roped off, conspicuously posted ~~and a flashing light shall be activated as a warning device~~. In lieu of the stay time specification of the ~~RWP~~, direct or remote (such as use of closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities within the area.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Licensee initiated changes to the PCP:

1. Shall be submitted to the Commission in the semi-annual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

   a. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

   b. A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

*Health Physics personnel or personnel escorted by Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are otherwise following approved plant radiation protection procedures for entry into high radiation areas.

**Measurement made at 18" from source of radioactivity.