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50-362 San Onofre Nuclear Station, Unit 3, Southern Californ 05000362
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MIRAGLIA,F. Resource & Scheduling Branch

SUBJECT: Forwards responses to open items & questions which will become part of amend 23 distribution,per 801107 ltr.

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

TELEPHONE
(213) 572-1401

January 14, 1981

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

Enclosed are sixty-three (63) copies of responses to numerous NRC Open Items and questions identified in the NRC letter dated November 7, 1980, and meetings with the NRC staff during the week of December 15, 1980. Enclosure 1 is a list of the responses which are included in Enclosure 2.

Direct distribution of these responses will be made as part of the Amendment 23 distribution and will be in accordance with the service list provided by SCE's letter of October 29, 1979. An affidavit attesting to the fact that distribution has been completed will be provided within ten (10) days of docketing of Amendment 23.

Please let me know if you have any questions or need any additional information.

Very truly yours,

KPB

Enclosures

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1/63

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ENCLOSURE 1

RESPONSES TO NRC OPEN ITEMS

San Onofre Nuclear Generating Station
Units 2 and 3

January 14, 1981

Open Item No.	Open Item
2	Toxic Gas Hazards
7	Reactor Internals Analysis
16	ECCS Analysis - NUREG-0630
22	P-T Limit Curves
25	Shutdown Cooling Design, RSB5-1
28	Containment Purging
37	Secondary Water Chemistry
39	Resumes of Plant Personnel
41	NARC Responsibilities
44	Inadvertent Boron Dilution
	Miscellaneous
	Startup Testing
032.39	Drawings for Aux. Feedwater Valves

ENCLOSURE (2)

Responses to NRC Open Items

2. TOXIC GAS HAZARDS

Question 312.47

With respect to your analysis of toxic gas hazards from transportation accidents, we are unable to verify the motor carrier accident rate which is presented in Section 6.4 of the FSAR. The value of 2 X 10^{-10} accidents per mile used in Section 6.4 is about four orders of magnitude less than the truck accident rate based on nationally averaged statistics used in FSAR Section 2.2 analyses. Thus, the estimated need for control room operator protection may have to extend beyond the selected gases (chlorine, butane, and anhydrous ammonia). Our position is that you should substantiate the truck accident rate used in the toxic gas analysis or revise it accordingly.

Response

The toxic gas hazards analysis is being reevaluated in light of your concerns. In the interim, personnel in constant communication with the control room will provide continuous and visual monitoring of the I5 highway. Upon receipt of communications indicating an accident on the highway, control room personnel will manually isolate the control room until it is confirmed that no threat to the control room habitability exists. 23

Reference

FSAR section 6.4. No FSAR change was made.

7. REACTOR INTERNALS ANALYSIS

3.9A.2.1.2 Results

Results of maximum reactor vessel support reactions are given in table 3.9A-1 for the 350 in.^{2} RV outlet break.

It can be seen from table 3.9A-1 that the 350 in.^{2} inlet break produces the controlling values for all support forces and moments components.

3-112.9 Figure 3.9A-5 shows time history response of the reactor vessel upper horizontal support reaction with and without the internal asymmetric loads for the 350 in.^{2} inlet break. The horizontal support reaction with internal asymmetric loads can be seen to be about 50% higher than the support reaction without these internal effects.

3.9A.2.1.3 Conclusion

Results of the analysis for coolant pipe breaks at the reactor vessel
nozzles are given in table 3.9A-1 along with the loads specified for
3-112.8 design of the reactor vessel supports. The calculated loads on the reactor
vessel supports are less than the corresponding design loads. The loads
specified for design of the reactor vessel supports for response to reactor
coolant pipe breaks at the reactor vessel nozzles therefore result in a
conservative design basis.

3.9A.3 REACTOR INTERNALS

Dynamic systems analyses are being performed to verify the adequacy of the
structural design of the reactor internals during a postulated LOCA. A
general description of the methodology of these analyses is provided
below. The LOCA blowdown loads analysis for San Onofre Units 2 and 3 has
been completed and representative results are also presented. The dynamic
structural analysis of the internals is currently being performed. The
LOCA maximum stress intensities in the reactor internal components will be
determined using the combinations of the lateral and vertical LOCA time-
dependent loadings which result in the maximum stress intensities in the
structural analysis. These LOCA maximum stresses and the maximum stresses
resulting from the DBE will then be combined using the root sum square
method to obtain the total stress intensities. The total stress inten-
sities will be compared to the allowable stress intensities for faulted
conditions (see FSAR paragraph 3.9.5.4.1). It is expected that the
23 calculated total stress intensities will not exceed the allowalbe values.
This preliminary conclusion will be confirmed upon completion of the
dynamic structural analysis of the reactor internals, scheduled for
April 1981.

16. ECCS ANALYSIS - NUREG-0630

Question 231.34

The NRC staff has been generically evaluating three materials models that are used in ECCS evaluations. Those models predict cladding rupture temperature, cladding burst strain, and fuel assembly flow blockage. We have (a) discussed our evaluation with vendors and other industry representatives (Reference 1), (b) published NUREG 0630, "Cladding Swelling and Rupture Models for LOCA Analysis" (Reference 2), and (c) required licensees to confirm that their operating reactors would continue to be in conformance with 10 CFR 50.46 if the NUREG 0630 models were substituted for the present materials models in their ECCS evaluations and certain other compensatory model changes were allowed (References 3 and 4).

Until we have completed our generic review and implemented new acceptance criteria for cladding models, we will require that the ECCS analyses in your FSAR be accompanied by supplemental calculations to be performed with the materials models of NUREG 0630. For these supplemental calculations only, we will accept other compensatory model changes that may not yet be approved by the NRC, but are consistent with the changes allowed for the confirmatory operating reactor calculations mentioned above.

Please provide the supplemental calculations described above.

References

1. Memorandun from R. P. Denise, NRC, to R. J Mattson, "Summary Minutes of Meeting on Cladding Rupture Temperature, Cladding Strain, and Assembly Flow Blockage," November 20, 1979. Available in NRC for inspection and copying for a fee.

2. D.A. Powers and R. O Meyer, "Cladding Swelling and Rupture Models for LOCA Analysis," NRC Report NUREG 0630, April 1980. Available from the NRC Division of Technical Information and Docket Control.

3. Letter from D. G. Eisenhut, NRC, to all Operating Light Water Reactors, dated November 9, 1979. Available in NRC PDR for inspection and copying for a fee.

4. Memorandum from H. R. Denton, NRC, to Commissioners, "Potential Deficiencies in ECCS Evaluation Models," November 26, 1979. Available in NRC PDR for inspection and copying for a fee.

Response

A supplemental calculation utilizing the material models of NUREG-0630 is being performed. The calculation will also include use of the heat transfer portion of C-E's alternate flow blockage and heat transfer model as described for NRC in Enclosure 1-P of Reference (1). This alternate heat transfer model is that used in supplemental calculations for C-E operating reactors. The operating reactor supplemental calculations were provided 23

to NRC by the individual utilities and were subsequently approved in early 1980.

The supplemental calculation for San Onofre Units 2 and 3 will consider the
limiting large break (1.0 x double ended guillotine cold leg break) as
defined in subsection 6.3.3 of the FSAR. The purpose of the supplemental
calculation is to demonstrate that the conclusion given in FSAR subsec-
23 tion 6.3.3, that San Onofre complies with the ECCS acceptance criteria of
10CFR50.46, remains valid.

Reference

No FSAR change was made, subsection 6.3.3; 10CFR 50.46.

1. C-E Letter to NRC LD-78-069 dated September 18, 1978.

22. P-T LIMIT CURVES

Question 121.23

Revise the pressure-temperature limits, presented in Figures 16.3-7A and 16.3-7B of the Technical Specifications, to reflect data requested in Question 121.19.

Response

Revised pressure-temperature curves for San Onofre Unit 2 have been provided (figures 16.3-7A and 16.3-7B). Revised curves for Unit 3 will be provided later. Table 121.23-1 is provided to show heatup, cooldown, and limiting material data. 23

Reference

See revised FSAR figures 16.3-7A and 16.3-7B.

Table 121.23-1

SAN ONOFRE UNIT 2
HEATUP, COOLDOWN AND LIMITING MATERIAL DATA
0-10 YR.

	Heatup	
	Press (PSIA)	Temp (F°)
Bolt Up (Start)	0	52 + 50.4 = 102.4
Isobaric to	0	125
Isothermal to	443	125
30 Deg/Hr to	540	165
Isobaric to	540	245
60 Deg/Hr to	1120	255
60 Deg/Hr to	2250	315
	Cooldown	
23 Start (Minimum)	2250	250
100 Deg/Hr	1250	202
Isothermal to	540	202
Isobaric to	540	102
Isothermal to	0	102.4
	Limiting Materials	
Upper Shell Course	RT_{NDT} = 40F	
RC Pump Flange Cover	RT_{NDT} = 90F	

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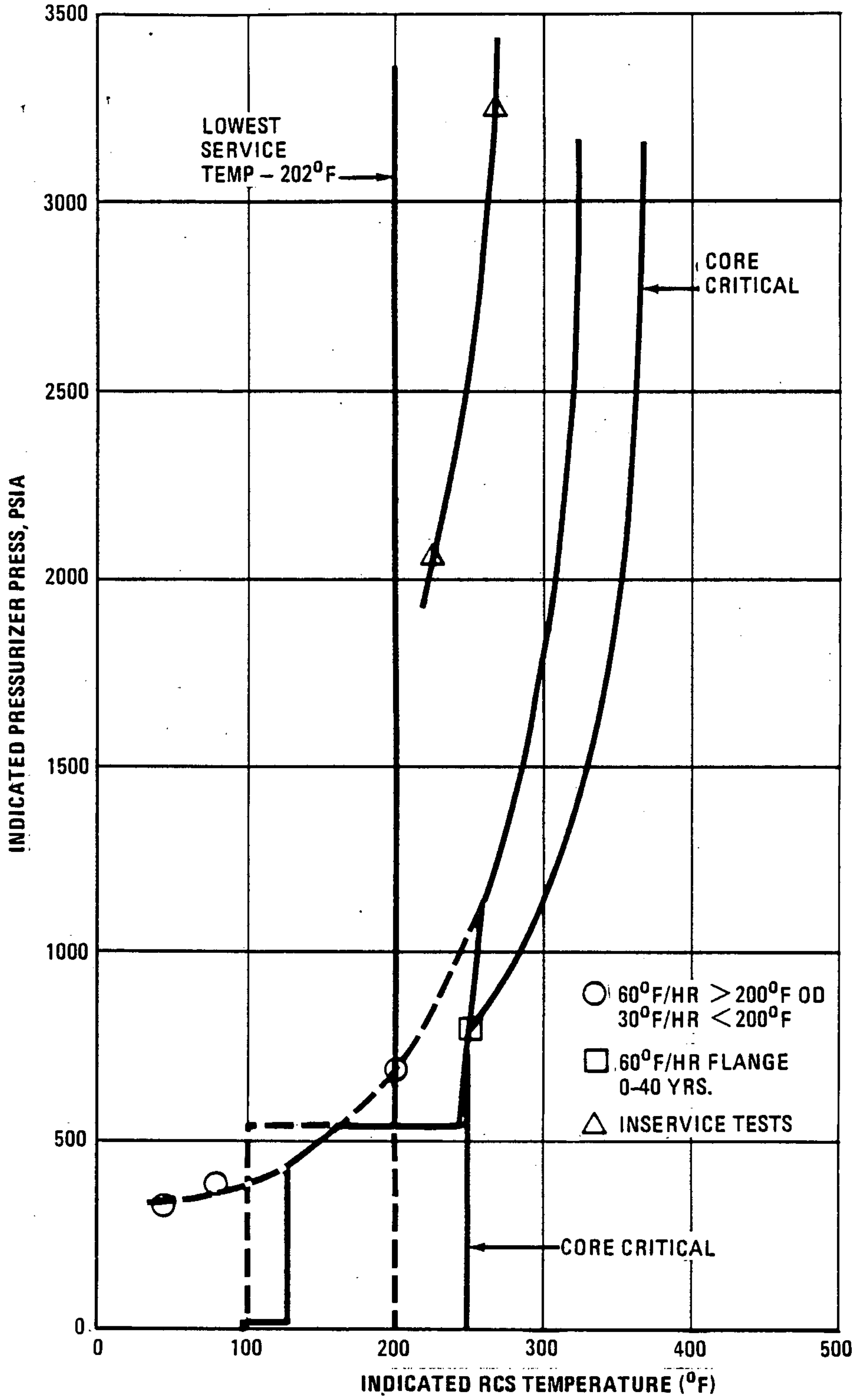
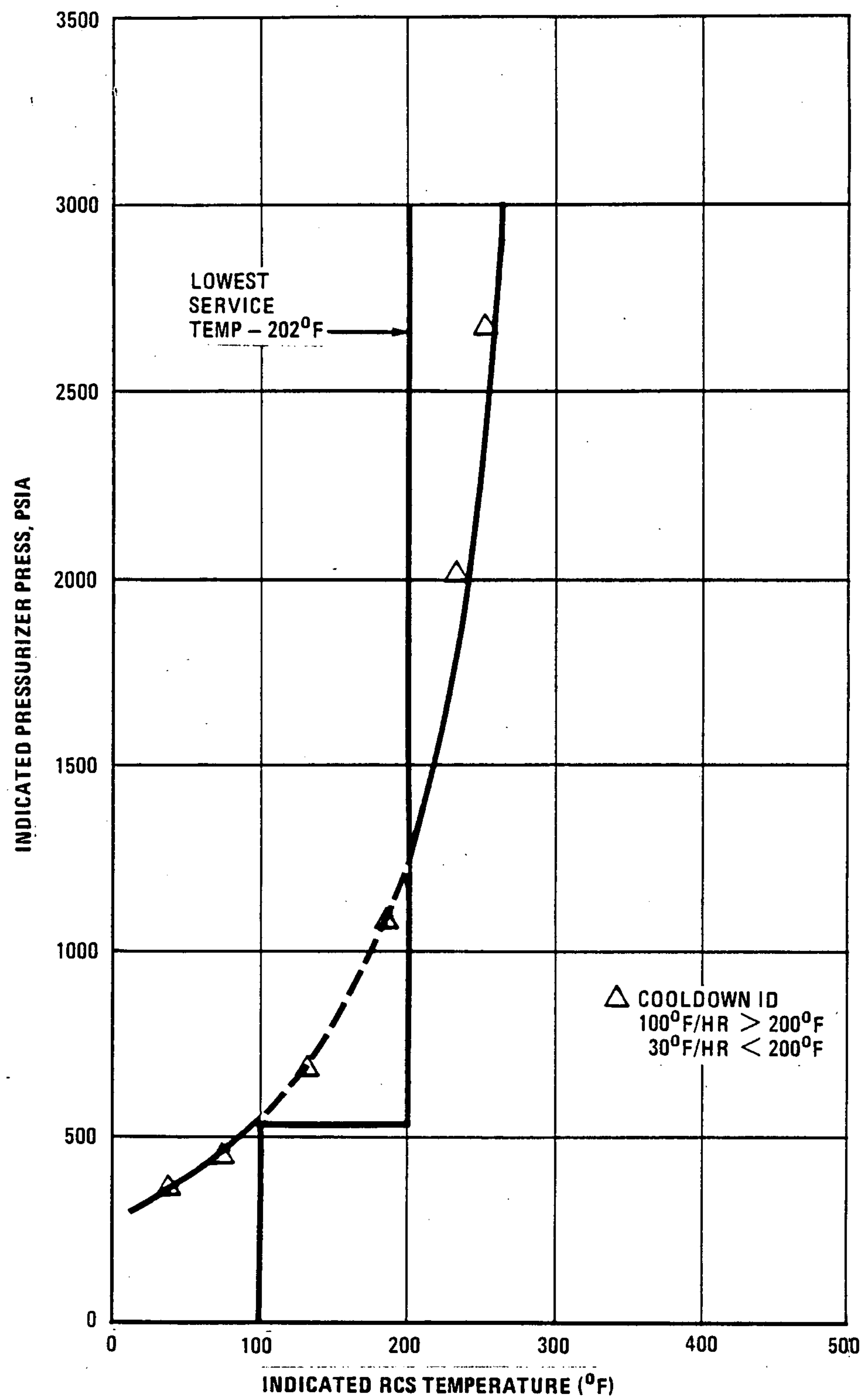


SAN ONOFRE NUCLEAR GENERATING STATION Units 2 & 3
HEATUP RCS PRESSURE/TEMPERATURE LIMITATIONS FOR: SCE II 0-10 YRS
FIGURE 16.3-7A



SAN ONOFRE NUCLEAR GENERATING STATION
Units 2 & 3

COOLDOWN
RCS PRESSURE/TEMPERATURE
LIMITATIONS FOR: SCE II
0-10 YRS

FIGURE 16.3-7B

25. RSB 5-1

Question 212.164

The staff has reviewed the shutdown cooling system design of San Onofre 2 and 3 for compliance to Reactor Systems Branch Technical Position 5-1 (as to be implemented for Class 2 plants). We have concluded that your present design does not meet that part of BTP 5-1 which requires the operator to be able to bring the plant from normal operating conditions to SDCS entry from the control room. It is our understanding that at least nine (9) valves in the SDCS train need to be manually repositioned from outside of the control room in order to realign from the safety injection to the SDC mode of operation.

It is the staff position that the SDCS design of San Onofre 2 and 3 be revised to comply with the above. We request that you submit the appropriate documentation of your design revision for staff approval prior to installation. Included in your submittal should be an evaluation which demonstrates that the modifications made do not significantly reduce the reliability of ECCS.

Because of the extent of the modifications necessary for compliance, we do not require that compliance be completed prior to your scheduled OL issuance. Rather, we will accept an extended schedule for completing the necessary design revisions. We propose that an acceptable schedule for completing the necessary design revisions is by the end of your first refueling outage.

Your response should acknowledge your acceptance of the staff position and either the acceptability of our proposed implementation schedule or a justifiable alternate schedule.

Response

The SDCS will be redesigned to permit realignment from the safety injection mode to the shutdown cooling system mode from the control room. Because the design changes required to establish this objective have not been finalized no schedule commitment for this change can be made at this time, however, it is the applicants intent to complete the modifications at the first refueling outage. A firm schedule commitment for completion of these modifications will be provided April 1981.

The preliminary design for the San Onofre Units 2 and 3 shutdown cooling system was described to the NRC in the December, 1980 meetings. Information was requested concerning the preliminary design and is provided in the following paragraphs.

A review of the design of the SONGS 2 and 3 shutdown cooling system (SDCS) has been conducted in order to determine what system modifications will be necessary in order to provide the capability of achieving a safe shutdown condition from the control room. The SDCS modifications described below are believed to meet the objectives of the BTP 5-1 position that requires the capability to initiate shutdown cooling from the control room. In 23

accordance with NRC implementation objectives, the modifications have been selected so that implementation may be completed at the first refueling outage.

Some SDCS equipment and piping serve several safety functions. Parts of the SDCS are aligned for automatic operation in an emergency core cooling or containment spray operating mode during normal power operations. The local manual actions required to initiate shutdown cooling result from the dual service of this equipment. Manual operation was selected in the initial design to minimize the potential for spurious component actuation that could affect emergency core cooling performance. The SDCS design modifications that have been proposed to eliminate the need for local valve operation include hardware modifications and normal plant operating mode alignment changes. Specific hardware changes are presented first; a discussion of their effect on ECCS operation and their use in achieving a safe shutdown from the control room follows.

A simplified flow diagram showing the proposed SDCS hardware modifications is given in figure 212.164-1. The manual valves which originally required local manual operation to initiate shutdown cooling are identified in table 212.164-1. The hardware modifications that are proposed to eliminate local manual actions are summarized in table 212.164-2. The flow diagram, figure 212.164-1, illustrates operation of the shutdown cooling equipment in an emergency core cooling mode. It is important that the proposed modi-
23 fications do not significantly affect the emergency core cooling function.

Components of the SDCS are aligned to perform an emergency core cooling function during normal power operations. Upon a safety injection actuation signal, the low pressure safety injection pumps are automatically started and the four header valves (9322, 9325, 9328, and 9331) automatically open. The proposed modifications do not change the initiation of ECCS operation.

Three areas where modifications have been made involve the system boundary. First, the low pressure safety injection pump minimum flow isolation valves 063, 037 were considered. Motors will be added to these valves. During normal operation these valves must be open; during shutdown cooling they are closed. Provisions will be provided to remove power from the valve during normal operation to prevent spurious closure. Therefore, no adverse effect on ECCS operation results from this modification. Next, changes at valve 015 and 018 were considered. These valves were normally closed to provide suction line separation in the emergency core cooling mode of operation. This is desirable to prevent return of sump fluid to the RWT under selected single failures. Under the modified system the valves remain open and check valves are added to provide the separation. The remaining boundary area is the set of isolation valves around the shutdown cooling heat exchangers. These are valves 039, 038, 001, and 002; they function to separate the containment spray system from the ECCS. Motors are to be added to these valves. A single failure resulting in the opening of one of these valves will not result in the loss of ECCS flow and will have an effect on only one spray train. Therefore, power removal was considered

unnecessary. The capability to perform the system safety functions is not diminished by this change.

The final area of change that has the potential to influence emergency core cooling performance is the area around the flow control valve 0306. A summary of the intended functions is provided on table 212.164-3. During normal power operation and during ECCS operation, all valves in the 0306 and 0306 bypass segments will be open and power will be removed. The 0306 valve will have its failure position changed to fail open. For the purpose of evaluating system performance, this arrangement is considered passive and does not affect system availability.

In summary, the modifications proposed do not reduce the reliability of the emergency core cooling system when the performance of the system is evaluated on the basis of single failure capability.

The modifications described above provide control room operability of all valves required to initiate and control the shutdown cooling system to achieve safe shutdown conditions. A minimum set of shutdown cooling equipment needed to achieve a safe shutdown is shown on figure 212.164-2. A redundant set is available using the other heat exchanger, pump, and associated valves. Two items are important with regard to shutdown cooling system operation when achieving a safe shutdown; power restoration to selected valves and use of alternate procedures to control the cooldown rate. 23

As indicated in the discussion of the emergency core cooling function, power removal was used on selected valves to satisfy single failure considerations. Power restoration is required prior to initiating the use of the system for shutdown cooling. Power restoration is achieved at the motor control center. This is a single area immediately above the control room. It is remote from the process piping. The action required is of short duration and repeated access is not required.

Control of the cooldown rate will differ from the normal shutdown process. Valves 0306 and 9316 are not used for system flow control; both valves remain in an open position and will fail open on loss of power. Resistance through the 0306 valve path is preset to limit heat exchanger bypass flow. To initiate shutdown cooling, the bypass around valve 0306 is closed and flow is introduced through the heat exchangers by opening valves 038, 039, 001, and 002. Cooldown rate is controlled by the use of valve 001 or 002 rather than valve 9316. This method reduces the system capacity to the extent that some bypass flow will always exist. Sufficient capability exists to achieve cold shutdown conditions within 36 hours.

Reference

None.

Table 212-164-1
VALVES REQUIRING LOCAL MANUAL ACTION FOR INITIATION
OF THE SHUTDOWN COOLING SYSTEM

23

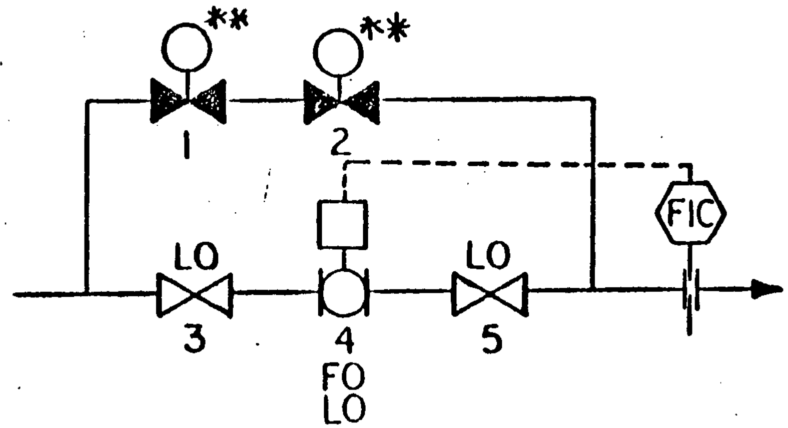
Valve Number	Function	Action
015 018	Provides separation of trains of suction. Prevents potential of blow back to RWT.	Open
039 038	Separate CS and ECCS functions Standby	Open
001 002	Separate CS and ECCS functions Standby	Open
153	Establish flow control for SDC	Close
037	Isolate min flow	Close
063	Isolate min flow	

Table 212.164-2
MODIFICATIONS TO ELIMINATE MANUAL ACTIONS

23

Valve Number	Modification	ECCS Alignment Standby
015/018	Add check valve in series	Open
039/038	Add motor	Closed
001/002	Add motor	Closed
153	Add motor Add motor valve in series Power lockout	Open
037/063	Add motor Power lockout	Open

Table 212.164-3
PROPOSED REVISION



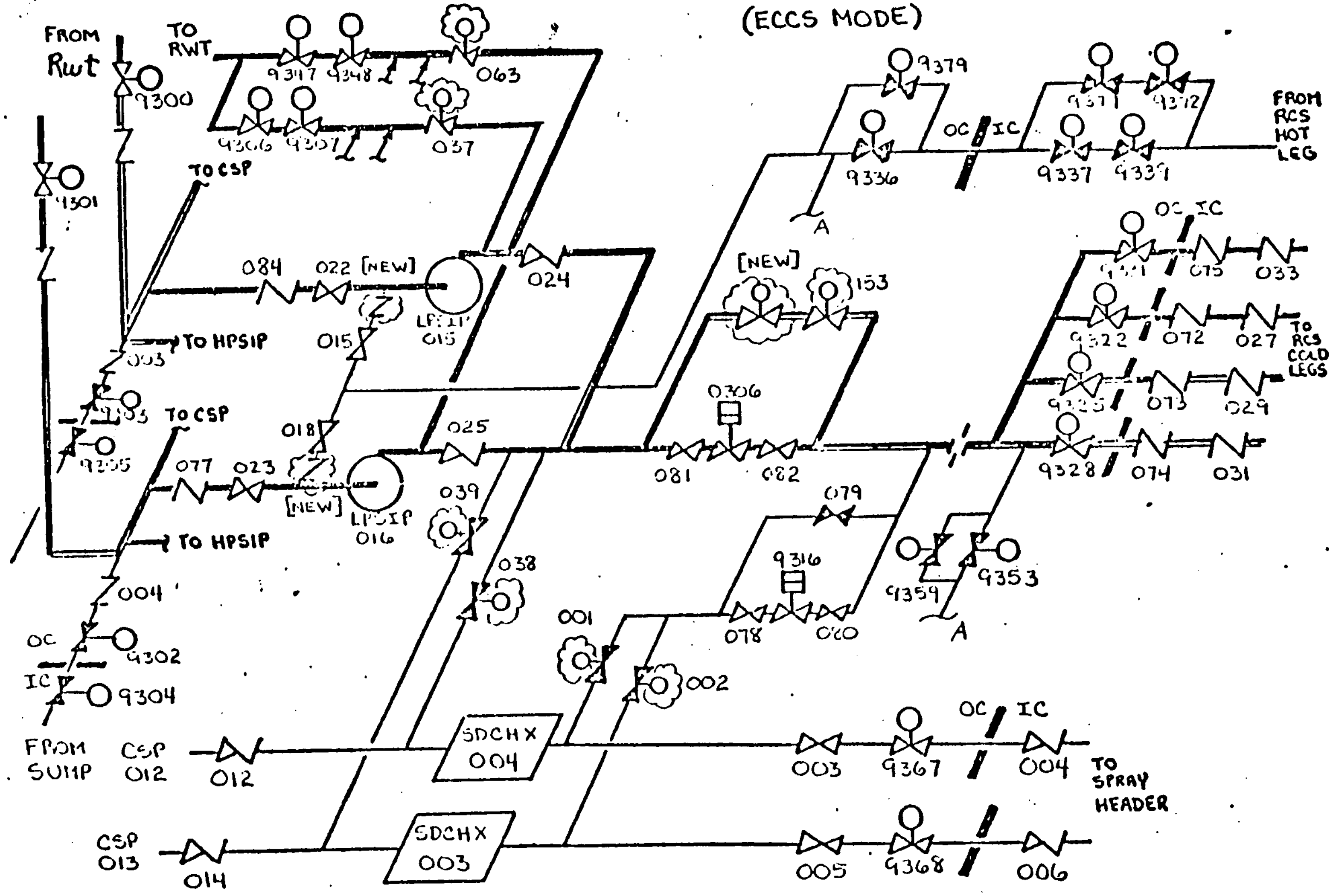
No.	ECCS Valve Position	Comment	Normal SDC Valve Position	Comment	Safe Shutdown or Valve Position	Comment
1	Open	Power lockout	Closed		Closed	Power restored
2	Open	Power lockout	Closed		Closed	Power restored
3	Open	Position set for safe SDC limit	Open	Position set for safe SDC limit	Open	Position set for safe SDC limit
4	Open	Power lockout	Throttle	Valve controlled to maintain total flow	Open	No throttling
5	Open		Open		Open	

*Restoration of power requires access to space immediately above the control room.
**Valve No. 1 and 2 are on separate power trains.

23

FIGURE 212.164-1

SAN ONOFRE SHUTDOWN COOLING SYSTEM
MODIFIED FOR CONTROL ROOM OPERATION
(ECCS MODE)



DENOTES MODIFICATION

28. Containment Purging

OPEN ITEM NO. 28

Containment Purging

The reponse to NRC Question 022.23 and FSAR paragraph 16.3/4.6.5 have been revised (enclosed) consistent with the NRC's requirement for limiting mini purge operation to ≤ 90 hours per year.

Question 022.23

Your response to Item 022.12 indicates that the large volume purge system will be used during modes of operation when containment integrity is required. It is our position that the technical specifications addressing limiting conditions for operation (Section 16.3.6.5.1) should include the reactor operational modes 3 and 4; i.e., hot standby and hot shutdown. Additionally, we will require that Item 1.a of Branch Technical Position CSB 6-4, regarding valve operability, be satisfied.

Response

A mini-purge system has been incorporated in the design of San Onofre Units 2 and 3. The mini-purge system is designed to operating during reactor operational modes 1, 2, 3 and 4 to minimize the operator dose from radioactive noble gases. A detailed description of the mini-purge system is provided in FSAR subsection 9.4.1. The limiting conditions for operation for the large volume purge system, are provided in 16.3.6.1.1.1. The limiting conditions include reactor operational modes 3 and 4.

Operation of the containment normal purge system has been limited as specified above based upon allowable unrestricted operation of the mini purge system. The mini purge system design is consistent with the requirements of BTP CSB 6-4 as previously noted in responses to NRC questions 022.12, 022.23 and 022.62. Since the mini purge system meets all the NRC Standard Review Plan requirements, the Applicants' consider the NRC's request for limiting purging to $\leq$ 90 hours per year to be an arbitrary position.

The Applicants agree to limit purging to $\leq$ 90 hours per year. However, if the NRC develops an acceptable alternative position relative to containment purging, the Applicants' reserve the right to use the acceptable alternative position.

Reference

See response to Question 022.12, and FSAR paragraphs 9.4.1 and 16.3/4.6.1.1.1 and revised FSAR paragraph 16.3/4.6.5

16.3/4.6.5 Containment Ventilation System

16.3.6.5.1 The containment normal purge supply and exhaust isolation valves shall be closed.

APPLICABILITY: Modes 1, 2, 3, and 4

ACTION: With one containment normal purge supply and/or one exhaust isolation valve open, close the open valve(s) within one hour or be in at least HOT STANDBY within the next six hours and in COLD SHUTDOWN within the following 30 hours.

16.3.6.5.2 Operation of the containment mini purge system to less than or equal to 90 hours per 12 months.

APPLICABILITY: Modes 1, 2, 3, and 4

ACTION: 1. With the total operating time for the containment mini purge system exceeding 90 hours per 12 months, close the open mini purge supply and exhaust isolation valves within one hour, or be in at least HOT STANDBY within the next six hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

16.4.6.5.1 The containment normal purge supply and exhaust isolation valves shall be determined closed at least once per 31 days.

16.4.6.5.1 The containment mini purge supply and exhaust isolation valves shall be determined OPERABLE per Section 4.6.3.4

37. Secondary Water Chemistry

NRC CHEMICAL ENGINEERING BRANCH
SECONDARY WATER CHEMISTRY QUESTIONS
RECEIVED DECEMBER 16, 1980

Question 2

In Section 1.2.3.1, Wet Storage - Short Duration, on page 12, it states that normal operating limits will be maintained for wet storage of short duration. Table 1.2-3 on the same page lists the limits for steam generator at wet storage - short duration. These limits are different from these in Table 1.1-1 for steam generator blowdown during normal operation. The limits in both Table 1.1-1 and Table 1.2-3 differ from the CE recommended values for wet layup in steam generator:

	Table 1.2-3 Wet Storage Short Duration	Table 1.1-1 Normal Operation	CE Recommendation
pH	9.0 ± 0.5	8.2 - 9.2	9.8 - 10.2
Conductivity	$<$15 umho/cm	7 umho/cm	N/A
Hydrazine	$1.5 \times O_2$ (15 ug/l)	NA	200 ± 50 ppm
Ammonia	NA	NA	$<$10 ppm
Nitrogen	NA	NA	$>$5 psig

Response

The Secondary Water Chemistry Monitoring Program, page 12, has been clarified by defining quasi-normal operating limits for wet storage of short duration.

High hydrazine concentrations (circa 200 ppm) are not desirable for Short Duration Wet Storage ($\leq$4 days) because of the large quantity of ammonia produced upon return to service:

$$2N_2H_4 \xrightarrow{>250^oF} 2\ NH_3 + N_2 + H_2$$

These lower hydrazine levels account for the differences between the CE pH values and those listed. The parameter Ammonia has been added to Table 1.1-1 with limits $\leq$1 mg/l and to Tables 1.2-3 and 1.2-4 with limits $<$10 mg/l.

Reference

Secondary Water Chemistry Monitoring Program For San Onofre Nuclear Generating Station, Units 2 and 3, January, 1981 (Revision 1)

Chemical Procedure SO23-III-2.3, Revision 2, Secondary System Chemical Limits and Sampling Frequencies.

TABLE 1.1-1
OPERATING CHEMISTRY LIMITS
SECONDARY SYSTEM - STEAM GENERATOR BLOWDOWN

Parameter	Normal*	Analysis Frequency	Transient Limit**	Consider Immediate Shutdown#
pH @ 25°C	8.2-9.2	(Continuous Monitor) 1/day	7.5 - 8.2 9.2 - 9.5	<6.5 or >10.5
Conductivity @ 25°C	<7 μmho/cm***	(Continuous Monitor) 1/day	≤15 μmho/cm	NA
Chloride	<100 μg/l****	1/day	NA	NA
Ammonia	≤1 mg/l	1/day	NA	NA
Suspended Solids	<1 mg/l	1/week	≥10 mg/l	NA
Free Hyrodxide	(Analyze when pH is outside normal range)			>5 mg/l
Silica	<1 mg/l	1/week	10 mg/l	NA
Dose Equivalent I-131	<0.01 μCi/l	3/week	NA	NA

* The normal chemistry conditions can be maintained by a coastline plant using sea water cooling but with little or no condenser leakage. If the normal specifications are exceeded, immediate investigation of the problem is initiated, sampling frequency increased to the abnormal level (at least once per 2 hours), and blowdown increased. If condenser leakage is indicated, leak isolation procedures are instituted.

** The transient steam generator limits are allowed to permit operations with minor system fault conditions until the affected component can be isolated and/or repaired. If the abnormal limits are exceeded for greater than 4 hours, shutdown procedures are considered.

*** Alarm set at 4.0 μmho/cm (CE Recommendation).

****CE limit.

\# NA indicates that no action other than correcting parameters back to acceptable limits is required.

Wet storage outage conditions will be monitored no less than twice weekly; and samples taken from the hotwells will be analyzed for pH, conductivity and chloride, and those taken from the feedwater and steam generators for pH, conductivity, dissolved oxygen and hydrazine. Quasi-normal operating limits will be maintained for wet storage outage protection of short duration. The system will be circulated for 30 minutes prior to sampling — if at all possible.

NOTE: Quasi-normal operating limits are normal limits that are less restrictive; thus, allowing more flexibility during outage periods.

TABLE 1.2-3
OUTAGE PROTECTION
Wet Storage - Short Duration ($t_{out} \leq$ 4days)*

	Hotwells	Feedwater Heaters	Steam Generators	Aux. Blr.	Aux. Blr. Deaerator
pH @ 25°C	9.0 ± 0.2	9.0 ± 0.2	9.0 ± 0.5	9.0 ± 0.5	9.0 ± 0.2
Conductivity (Specific) @ 25°C	<10 μmho/cm	<10 μmho/cm	<15 μmho/cm	<15 μmho/cm	<10 μmho/cm
Chloride	<0.15 mg/l	NA	<0.15 mg/l	<1.0 mg/l	NA
Dissolved Oxygen	<100 μg/l	<10 μg/l	<10 μg/l	<10 μg/l	<10 μg/l
Hydrazine	NA	$\geq 2 \times O_2$	$\geq 2 \times O_2$	$\geq 2 \times O_2$	$\geq 2 \times O_2$
Ammonia	<10 mg/l	<10 mg/l	<10 mg/l	<10 mg/l	<10 mg/l

* Vacuum on main condenser; steam pegging on shell side of feedwater heaters and steam generators.

1.2.3.2 Wet Storage - Extended Duration (4 days $< t_{outage}$ <2 months)

If vacuum cannot be maintained on main condenser and on the shell side of the 5th and 6th point heaters, then these systems must be drained while still hot (≥90°F). Also, if the main circulating water pumps are shutdown, the water boxes should be drained.

If steam pegging protection is not available, then a nitrogen overpressure of 5 psig should be applied to the steam generators; and the shell sides of the 1st through 4th point heaters should be flooded with demineralized water treater with 200 μg/ℓ hydrazine. These protective measures should be done prior to breaking vacuum on the main condenser and prior to the attainment of ambient temperature.

Wet storage outages of extended duration should be monitored at least twice weekly; and samples taken from the steam generators and feedwater heaters shell side should be analyzed for pH, conductivity and hydrazine; and checked for nitrogen overpressure. The pH, hydrazine and nitrogen overpressure within these systems should be maintained at 10.0 ± 0.2, 200 ± 50 N_2H_4, and ≥5.0 psig N_2, respectively. Prior to sampling, the system should be circulated for 30 minutes — if at all possible.

TABLE 1.2-4
OUTAGE PROTECTION
Wet Storage - Extended Duration (4days < t_{outage} <2 months)*

	Feedwater Heaters		Steam		Aux. Blr.
	Tube Side	Shell Side	Generators	Aux. Blr.	Deaerator
pH @ 25°C	10.0 ± 0.2	10.0 ± 0.2	10.0 ± 0.2	10.0 ± 0.2	9.0 ± 0.2
Hydrazine	200 ± 50 mg/1	200 ± 50 mg/1	200 ± 50 mg/1	200 ± 50 mg/1	100 ± 50 mg/1
Dissolved Oxygen	100 μg/1	NA	100 μg/1	100 μg/1	100 μg/1
Ammonia	<10 mg/1	<10 mg/1	<10 mg/1	<10 mg/1	<10 mg/1

* No vacuum on main condenser, hotwells drained; N_2 overpressure on shell side of feedwater heaters and on steam generators.

1.2.3.3 Dry Storage (t_{outage} > 2 months)

Hotwells should be drained while above ambient temperature (~ 92°F) and access panels opened to allow thorough drying of internal condenser surfaces.

Feedwater heaters tube side and shell side should be drained while above ambient temperature (6th, 5th and 4th @ > 115°F; 3rd and 2nd @ > 220°F; and 1st @ 240°F).

39. Resumes of Plant Personnel

OPEN ITEM NO. 39

Resumes of Plant Personnel

Consistent with a conversation between the NRC reviewer (B. Benedict) and F. R. Nandy of SCE on January 8, 1981, the following FSAR sections have been revised (enclosed) consistent with the clarification requested by the NRC reviewer:

Section 13.1.2.2.1
Section 13.1.2.2.3

Table 13.1A-1 (Sheet 5 of 5)

The FSAR will be revised to reflect these revisions in the next FSAR amendment.

The Units 2 and 3 on-duty operating shift crews will be composed as shown in table 16.6-1 and meet the requirements outlined in paragraph 16.6.2.2 describing the facility staff. Manpower in excess of four shift crews is provided. Each member of the facility staff will meet or exceed the minimum qualifications recommended in Regulatory Guide 1.8, Personnel for Nuclear Power Plants, for comparable positions.

The employees assigned to San Onofre will be trained as described in section 13.2. All personnel can be rotated between Unit 1 and Units 2 and 3, except those employees performing duties requiring an NRC operating license.

13.1.2.2 Plant Personnel Responsibilities and Authorities

13.1.2.2.1 Overall Plant Management

The Plant Manager of the San Onofre Nuclear Generating Station is responsible for overall plant management of Units 1, 2, and 3. In his absence the Superintendent of Units 2 and 3 assumes this responsibility. In the event of unexpected contingencies of a temporary nature, the Watch Engineer on duty at Units 2 and 3 will be responsible for overall plant operations. In addition, the Plant Manager can designate in writing other qualified personnel to assume overall plant responsibility in his absence.

The Plant Manager reports to the Manager, Nuclear Generation

He also communicates with the Supervising Engineer, who coordinates the technical support provided by the company's headquarter staff, as described in subsection 13.1.1. Reporting to the Plant Manager are five key supervisors:

- Superintendent, Unit 1: responsible for the operation and maintenance of Unit 1.
- Superintendent, Units 2 and 3: responsbile for the operation and maintenance of Units 2 and 3.
- Supervising Engineer (station): responsible for the engineering and technical support for the three units.
- Security Supervisor: responsible for station security.
- Station Administrative Supervisor: responsible for administrative support, accounting, procurement and warehousing.

All but the Superintendents will be responsible for activities at all three units. It is estimated that they will spend one-third of their time with Unit 1 related matters and two-thirds on Units 2 and 3 activities once all units are in full operation.

13.1.2.2.2 Operations Supervision and Operating Shift Crews

The Supervisor of Plant Operation, Units 2 and 3, is responsible for the operation of the two units and will possess a Senior Reactor Operator License for Units 2 and 3. He reports to the Superintendent and stays in close communication with the other station supervisors with regard to all activities involving Units 2 and 3.

An operating crew for the Units 2 and 3 control room will normally consist of one Watch Engineer and one Operating Foreman (both will possess Senior Reactor Operator licenses), two Nuclear Control Operators, and three Nuclear Assistant Control Operators (who will possess Reactor Operator licenses), and two Nuclear Plant Equipment Operators. The minimum shift crew composition for various modes of reactor operations is shown in detail in table 16.6-1. The Watch Engineer is the supervisor of the shift and is responsible for seeing that all plant operations are conducted in accordance with appropriate station orders, station operating instructions and technical specifications. Under the supervision of the Watch Engineer, the Nuclear Control Operator directs the activities of the Nuclear Assistant Control Operators and the Nuclear Plant Equipment Operators. In addition, he keeps a record of all shift activities and establishes unit load as directed by the SCE dispatcher or as emergency conditions dictate. Nuclear Assistant Control Operators monitor the status and make adjustments as needed to maintain control of the various plant processes. Most of their duties are confined to the control room, although they perform routine inspections in other areas of the plant. In the absence of a Chemical Radiation Protection Technician, they make radiation and contamination surveys within the controlled area, obtain samples and test primary and secondary water chemistry.

During periods when the reactor is shut down, the Nuclear Assistant Control Operator makes routine inspections of nuclear steam supply system equipment within the containment, makes routine tests and clears and returns equipment to service as directed by the Nuclear Control Operator. They also inspect and lubricate plant equipment at regular intervals.

13.1.2.2.3 Engineering, Instrumentation and Radiation Protection Supervision

The station Supervising Engineer reports to the Plant Manager and supervises the engineering staff through two supervisors. The Supervisor of Nuclear Plant Instrumentation and the Supervisor of Plant Chemistry and Radiation Portection report to the **Plant Engineer**. Significant operating problems that are outside the capabilities of the San Onofre station staff are reviewed and acted upon by the Manager, Nuclear Generation to obtain a satisfactory resolution. The station staff communicates and cooperates with the headquarter's staff as necessary to resolve identified operating problems or obtain technical advice. The Supervising Engineer at San Onofre allocates his time among the three units at San Onofre, and will spend approximately two-thirds of his time on activities relating to Units 2 and 3. One of the two Supervising Engineers reporting to him will be assigned to Units 2 and 3 to assume proper engineering support of plant operations.

Table 13.1A-1
STATION PERSONNEL RESUME (Sheet 5 of 5)

Name, Title Responsibility, Authority	Educational Background	Professional Level Experience
R. V. Warnock Supervisor of Plant Chemistry and Radiation Protection Units 2 & 3 Supervises Chemical and Radiation Protection Engineers, Foremen, Engineering Aids and Technicians	San Diego State University BS Chemistry (1963) San Diego State University MS Nuclear Chemistry (1968) San Diego State University - additional courses in Electronics, Metallurgy (1970-1971) Atomics International - Basic Reactor Theory and Operation including training in radiation protection P.E., Corrosion Engineer, California (1977) Rockwell International - Health Physics Certification Review Course (1978) Oak Ridge Associated Universities Health Physics in Radiation Accidents (1980)	Solar Division of International Harvester - Research Engineer I, II contract research in materials development (1965-1972) Southern California Edison Co. - Assistant Chemical and Radiation Protection Engineer, San Onofre Nuclear Generating Station (1972-1976) - Supervisor of Plant Chemistry and Radiation Protection, San Onofre Nuclear Generating Station (1976 to present)

41. NARC Responsibilities

OPEN ITEM NO. 41

NARC Responsibilities

Consistent with a conversation between Mr. B. Bendict (NRC) and Mr. F. R. Nandy (SCE) on January 8, 1981, the response to NRC question 422.11A has been revised (enclosed) to reflect Mr. Benedict's concerns. These revisions are consistent with the proposed technical Specifications for San Onofre Units 2 and 3 which was submitted to the NRC on November 26, 1980.

The FSAR will be revised to reflect these revisions in the next FSAR amendment.

Question 422.11A (RSP)

We do not agree that the NARC review of reports and meeting minutes of the OSRC assures that they review the evaluations of proposed changes to procedures to verify that such proposed changes do not constitute unreviewed safety questions, or proposed changes in procedures which may involve an unreviewed safety question. Therefore, it is the staff's position that you modify the responsibilities of your NARC to include the review of:

1. evaluations of proposed changes to procedures completed under the provisions of 10 CFR 50.59(a) to verify that such proposed changes do not constitute an unreviewed safety question,

2. proposed changes in procedures which may involve an unreviewed safety question as defined in 10 CFR 50.59(c).

Amend your response to address this position.

Response

The NARC shall review

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.

This response is consistent with the proposed technical specifications for San Onofre Units 2 and 3 which was transmitted to the NRC on November 26, 1980

Reference

See FSAR paragraph 16.6.5.2.7. No FSAR change was made.

44. INADVERTENT BORON DILUTION

Question 212.163

At a meeting on August 15, 1980, the staff informed you that your response to question 212.152 was unsatisfactory. The Standard Review Plan (NUREG 75/087) Section 15.4.6 requires that redundant alarms not subject to a single failure be provided to alert the operator of an unplanned dilution event. The staff requests that you describe in detail the redundant alarms which will signal an unplanned dilution during all modes of operation including cooldown.

Response

In addition to the boron dilution alarm provided by the boronometer as discussed in response to Question 212.152, redundant alarms actuated by the source range nuclear instrumentation and annunciated in the control room will be provided to alert the operator to an unplanned boron dilution event in the subcritical operating modes.

Limiting boron dilution events in MODES 3, 4, 5 and 6 were analyzed to determine times to complete loss of shutdown margin, and corresponding neutron flux responses at the startup channel excore detectors. Based on these responses, startup channel alarm setpoints on high neutron flux were established to satisfy the requirements of SRP 15.4.6. This alarm setpoint protection replaces the original procedural response to NRC Question 212.152. In MODES 1 and 2, the operator will be alerted to a boron dilution by one or more of the following alarms: Power Dependent Insertion Limit alarm, high power level alarm or trip, T-average alarm, or high logarithmic power alarm or trip. A detailed discussion of these alarms is given in the response to Question 212.152. In the subcritical modes, the limiting boron dilution event results in the quickest approach to complete loss of shutdown margin, i.e., inadvertent criticality. The limiting dilution event in each subcritical mode was modeled using conservative plant and core parameters. The initial assumed shutdown margin for each event corresponded to the minimum shutdown margin required by the Technical Specifications for the assumed mode of operation. This analysis and the corresponding startup channel alarm setpoint provide protection for the situation when the RCS is partially drained in MODE 5 to permit system maintenance. Because the RCS liquid volume is reduced, and MODE 5 has the smallest required shutdown margin, a dilution event during this plant condition will result in the shortest time to criticality. The reduced RCS volume dilution event was not previously analyzed, but protection is provided by the startup channel alarm.

The boron dilution alarm setpoint calculation will consist of an alarm setpoint and allowable value, similar to the PPS setpoint calculation, and reset time interval requirements. The allowable value allows for measurable time dependent drift and calibration uncertainties.

The boron dilution alarm uses a fixed setpoint bistable that can be manually adjusted by the operator from the control room. The alarm will be set at a specified differential amount above the neutron flux input and must be reset periodically because the neutron flux input is continuously decreasing after shutdown. 23

The differential alarm setpoint will be calculated to be close to the input without causing spurious alarms. The alarm setpoint will remain fixed as the input decreases. At a specified time interval, the alarm setpoint will be reset at the specified differential above the input. This time interval will be based on a normal shutdown neutron flux decay curve and will be determined so that an alarm will be given within the boron dilution alarm requirements. If graphed over time, the setpoints will appear as decreasing steps above the normally decreasing neutron flux input. At all times, the alarm setpoint will initiate an alarm for a boron dilution transient in time for operator action as assumed in the safety analysis.

The boron dilution alarm setpoint will be calculated with the same method as the PPS setpoints - the C-E explicit setpoint calculation method. The maximum differential alarm setpoint analysis setpoint; i.e., the setpoint giving the minimum acceptable time for operation action; is determined in the safety analysis. The explicit method defines all uncertainties as explicit individual components; then statistically combines the components
23 into a total equipment uncertainty. The uncertainty components will include instrumentation errors, environmental errors, and bistable calibration and drift errors. Uncertainties associated with the decrease of the flux input between resets will also be factored into the setpoint.

The total equipment uncertainty is subtracted from the analysis setpoint to give the maximum differential that the alarm setpoint can be above the neutron flux input. The differntial alarm setpoint will be calculated so that the differential just before reset is less than the maximum differential. An allowable value will be calculated with the differential alarm setpoint to allow for calibration and time dependent drift uncertainties.

<u>References</u>

NRC Question 212.152 and its response; FSAR paragraphs 15.4.1.4.2, 15.4.1.4.3, and 7.7.1.1.2 are modified by this question response.

MISCELLANEOUS

Question 032.39

Section 7.3.1 of the FSAR states that the discharge valves of the emergency feedwater system are automatically closed to secure excess feedwater flow when the steam generator water level returns above the low level set point. Provide a detailed description of the operation of these valves, including logic and electrical schematic diagrams. Identify all valves involved in this operation.

Response

The San Onofre Units 2 and 3 emergency feedwater actuation signal (EFAS) automatically actuates the auxiliary feedwater system by fully opening the isolation and control valves to deliver a minimum feedwater flowrate of 700 gal/min to the intact steam generator(s). The EFAS is initiated for the intact steam generator either by a low steam generator level coincident with no low pressure trip present on the intact unit or by a low steam generator level coincident with a differential pressure between the two steam generators with the higher pressure in the intact unit.

The two-out-of four logic is provided independently for each steam generator. When steam generator water level returns to the reset point above the low level setpoint, the auxilliary feedwater system discharge valves will shut automatically as the EFAS is removed to secure excess feedwater flow. The EFAS will continue to function as required to maintain steam generator water level while the plant remains at hot standby or is brought to cold shutdown. Figure 032.39-1 shows the San Onofre Units 2 and 3 EFAS logic and FSAR figure 10.4-9 is the San Onofre Units 2 and 3 auxiliary feedwater system showing the system relationship of the valves, two motor-driven pumps and the turbine driven pump.

The third pump (motor-driven) has recently been added to the system to improve reliability resulting in a redesign of the piping system (FSAR subsection 10.4.9). The EFAS logic was not changed by this action. Subsection 7.3.1 changes to reflect the three pump system will be provided by January, 1980.

In response to an NRC request in the meetings held 12/15/80, electrical drawings are provided in accordance with table 1.7-1 for the auxiliary relay cabinet and auxiliary feedwater valves. Draft copies of the drawings were provided to NRC on 12/17/80. The drawings are:

23

Drawing No.	Description
30911-0	Elementary Diagram - Valve HV-4712
30920-0	Elementary Diagram - Valve HV-4714
30943-6	Elementary Diagram - Valve HV-4715
30946-2	Elementary Diagram - Valve HV-4731

Drawing No.	Description
30954-6	Elementary Diagram - Valve HV-4706
30956-5	Elementary Diagram - Valve HV-4713
30996-0	Elementary Diagram - Valve HV-4705
30997-0	Elementary Diagram - Valve HV-4730
54507-0	Control Logic Diagram - Aux Feed Iso Valves
54509-1	Control Logic Diagram - Aux Feed Valves
80-006-12-K	Aux Relay Cabinet Electrical Schematic (2 sheets) 23

Reference

FSAR subsections 7.3.1 and 10.4.9. FSAR table 1.7-1 was modified to include drawings discussed above.

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 18 of 56) 9

Drawing Number	Rev. No.	Date	Title	Section Reference	
30887	2	12/05/78	Elem Diag for HV6236 (Unit 2)	7.3.1.1.12.2	
30894	2	12/08/78	Elem Diag Reac Aux Chg Pump Suct Press Cont		
30898	5	05/25/79	Elem Diag Flooding Ind		
30899	1	03/12/79	Elem Diag for HV0517 (Unit 2)	7.3.1.1.4	
30911	0	09/24/80	Elem Diag Fdw & Cond - Aux Fdw Pump P504 Disch Cont Valve HV-4712		23-032
30913	0	03/19/79	Elem Diag Fdw & Cond Emer Fdn to St Gen Cont V Pos Ind		
30920	0	10/01/80	Elem Diag Fdw & Cond - Aux Fdw to St Gen E088 Iso Valve HV-4714		23-032
30939	3	07/23/79	Elem Diag Fdw & Cond Main Fdw Iso Vlv Sol		
30940	4	06/25/79	Main Feedwater Isol Valve Sol (HV4048) (Unit 2)	7.3.1.1.6	
30941	3	06/25/79	Main Feedwater Isol Valve Sol (HV4052) (Unit 2)	7.3.1.1.6	
30942	3	05/09/79	Elem Diag Fdwr & Cond Emer Fdwr Iso Vlv Sol (HV4714)		
30943	6	08/21/80	Emer Feedwater Isol Valve Sol (HV4715) (Unit 2)	7.3.1.1.6 7.3.1.1.7	23-032
30945	3	07/23/79	Elem Diag Fdwr & Cond Main Fdwr Iso Vlv Sol		
30946	2	05/09/79	Elem Diag Fdwr & Cond Aux Fdwr Isol Valve (2HV4731) (Unit 2)		
30947			Superseded by 30997		23

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 18a of 56)

Drawing Number	Rev. No.	Date	Title	Section Reference
30953	4	06/13/79	Feedwater to Steam Gen Control (HV4705) (Unit 2)	7.3.1.1.7
30954	6	08/21/80	Feedwater to Steam Gen Control (HV4706) (Unit 2)	7.3.1.1.7
30955	6	05/09/79	Feedwater to Steam Gen Control (HV4712) (Unit 2)	7.3.1.1.7
30956	5	05/09/79	Feedwater to Steam Gen Control (HV4713) (Unit 2)	7.3.1.1.7
30966	3	12/08/78	Aux Feedwater Pump Turb Steam Inlet Valve (HV4716) (Unit 2)	7.3.1.1.7
30996	0	10/01/80	Elem Diag Fdw & Cond - Aux Fdw Pump P140 Disch Cont Valve (HV4705)	
30997	0	10/01/80	Elem Diag Fdw & Cond - Aux Fdw to St Gen E088 Iso Valve (HV4730)	

23-032.39

23-032.39

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 42 of 56) 9

Drawing Number	Rev. No.	Date	Title	Section Reference	
-	-	-	ESFAS Auxiliary Relay Cabinet Technical Manual Schematic Diagrams: Fig. 4-4 Test Module Fig. 4-7, Sht 1, ESFAS Auxiliary Relay Cabinet Fig. 4-7, Sht 2, ESFAS Auxiliary Relay Cabinet		4.032.26
80-006 -12	K	-	Aux Relay Cabinet Electrical Schematic (Sheet 1 and 2)		23-032.39
900-D-44	3	10/03/77	Elementary Wiring Diagram Motor Operated Valves Sht 3 (B-1370-414-350)		9-032.38
922-075	0	09/29/76	RCP Mtr Speed Sensor 1LD (D-1370-414-020-D)	7.2 7.7	
924-029	3	07/07/75	Mcbd Temp Chan (1484-8824) (B-1370-413-101-B)	7.2 7.5 7.7	
924-030	3	07/07/75	MCbd Temp Chan (1484-8824) (B-1370-413-102-B)	7.2 7.5 7.7	9-032.38
924-032	3	07/07/75	Mcbd D/P Chan (0484-8824) (B-1370-413-105-B)	7.2 7.5	
924-035	5	02/23/76	Mcbd Press+Lvl Chan (0584-8824) (B-1370-413-109-B)	7.5 7.6	9-032.38
924-038	4	02/23/76	Mcbd Cvcs Temp Chan (1684-8824) (B-1370-413-201-B)	7.4 7.5 7.7	
924-042	3	07/07/75	Mcbd Cvcs Levl Chan (1684-8824) (B-1370-413-205-B)	7.4 7.5	
924-043	3	11/07/75	Mcbd Cvcs Prss Chan (1664-1200) (B-1370-413-207-B)	7.4, 7.5 7.7	9-032.38

MISCELLANEOUS

Startup Testing (Chapter 14 revisions)

Consistent with a conversation between Mr. B. Clayton (NRC) and Mr. F. R. Nandy (SCE) on January 6, 1981, the following FSAR sections have been revised (enclosed) to reflect Mr. Clayton's concerns:

Section 14.2.12.10
Section 14.2.12.53
Section 14.2.12.75
Section 14.2.12.95

The FSAR will be revised to reflect these revisions in the next FSAR amendment.

14.2.12.10 <u>Emergency Diesel Generator System</u>

14.2.12.10.1 Objective

To demonstrate the ability of the emergency diesel generators, and their support equipment to provide reliable emergency power and verify independence of emergency redundant onsite power supplies.

14.2.12.10.2 Prerequisites

A. Construction activities completed

B. All permanently installed instrumentation properly calibrated and operable

C. All test instrumentation available and properly calibrated

D. Appropriate ac and dc power sources available

14.2.12.10.3 Test Method

A. All control systems for the diesel and its auxiliaries will be tested

B. Manual control of the diesel generator will be demonstrated

C. Emergency starting controls and logic will be tested

D. The diesel generator will be load tested at full rated load

E. Proper load sequencer operation and system independence will be verified by performing a loss of normal power test on each emergency bus with the redundant bus isolated.

14.2.12.10.4 Acceptance Criteria

The diesel generators and their auxiliaries perform in accordance with section 8.3.1.1.4.7 and response to NRC question 423.29 part b, conformance with Regulatory Guide 1.108.

14.2.12.53 Excore Nuclear Instrumentation

14.2.12.53.1 Objective

To demonstrate proper operation of the excore nuclear instrumentation channels.

14.2.12.53.2 Prerequisites

A. Construction activities on the excore nuclear instrumentation system have been completed

B. Associated instrumentation has been calibrated

C. Support systems required for operation of the excore nuclear instrumentation system are available.

D. Appropriate ac and dc power sources available.

14.2.12.53.3 Test Method

A. Using external test instrumentation and/or internal test circuitry, simulate and vary input signals to the startup, safety and control channels of the excore nuclear instrumentation system.

B. Monitor and record all output signals as a function of variable inputs provided by external test instrumentation or internal test circuitry

C. Record the performance of audio visual indicators in response to changing simulated input signals

D. Demonstrate the independence of each channel.

E. Simulate failed conditions and verify proper system response.

14.2.12.53.4 Acceptance Criteria

The encore nuclear instrumentation channels operate as specified in section 7.7 of the FSAR.

14.2.12.75 CEDM Performance Test

14.2.12.75.1 Objective

A. To demonstrate proper operation of the control element drive mechanisms

B. To verify the proper operation of the CEA position indication systems and alarms

C. To measure CEA drop times.

14.2.12.75.2 Prerequisites

A. Construction activities completed

B. The CEDMCS acceptance test has been completed

C. All test instrumentation available and properly calibrated

D. RCS conditions are being maintained in steady-state at the desired temperature and pressure for the CEDM measurement

E. CEDM oil resistances have been measured for the RCS condition of the test

F. CEDM coolers available.

14.2.12.75.3 Test Method

A. Testing at the HOT SHUTDOWN condition will consist of:

   1. Each CEA will be withdrawn and inserted while recording appropriate position indications and alarm operations.

   2. The drop time of each CEA will be measured.

   3. Ten additional measurements of drop time will be made for the fastest and slowest CEAs.

B. Testing at hot, zero power conditions will consist of:

   1. Each CEA will be withdrawn and inserted while recording appropriate position indications and alarm operations.

   2. The drop time of each CEA will be measured

SPECIFIC INFORMATION
TO BE INCLUDED IN FSAR

14.2.12.95 Shutdown From Outside the Control Room

14.2.12.95.1 Objective

To demonstrate that the plant can be maintained in HOT STANDBY from outside the control room following a reactor trip.

14.2.12.95.2 Prerequisites

A. The reactor is operating at approximately 50% of rated power

B. A standby crew of operators are available in the control room at all times.

14.2.12.95.3 Test Method

The operating crew evacuates the control room (standby) crew remains in the control room at all times) and the reactor is tripped from outside the control room. The reactor is brought to HOT STANDBY and a cooldown is initiated by the operating crew from outside the control room. 23

14.2.12.95.4 Acceptance Criteria

The ability to bring the RCS to HOT STANDBY, maintain it in that condition, and to manually initiate a plant cooldown from outside the control room following a reactor trip has been demonstrated. Reference response to NRC question 423.29 part a, conformance with Regulatory Guide 1.68.2. 23