Consumers
Power
Company

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COPY

July 23, 1980

Director, Nuclear Reactor Regulation
Att Mr Dennis M Crutchfield, Chief
Operating Reactors Branch No 5
US Nuclear Regulatory Commission
Washington, DC 20555

DOCKETS 50-155 AND 50-255 - LICENSES DPR-6 AND DPR-20 -
BIG ROCK POINT AND PALISADES PLANTS - RESPONSE TO
EVACUATION TIME ESTIMATES - SITE EMERGENCY PLAN

Consumers Power Company was requested, by NRC letter dated November 29, 1979, to give information regarding estimates for evacuation of various areas around our Palisades and Big Rock Point Nuclear Plants.

Five copies of the Palisades and Big Rock Point evacuation time estimates, prepared by HMM Associates, have been sent to the NRC staff.

The results for the Palisades Plant show that evacuation clear time for the 0-10 mile area is approximately 2 hours for both summer and winter conditions. At our Big Rock Point Plant, the evacuation clear time for the 0-5 mile area is approximately 5 hours in the summer and approximately 16 hours in the winter. (Reference Consumers Power April 24, 1980 and NRC June 13, 1980 letters for basis of 5-mile Emergency Planning Zone.)

David P Hoffman (Signed)

David P Hoffman
Nuclear Licensing Administrator

CC JGKeppler, USNRC
NRC Resident Inspector-Palisades
NRC Resident Inspector-Big Rock Point

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Southern California Edison Company

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

July 31, 1980

Director of Nuclear Reactor Regulation
Attention: Mr. D. M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Project Management
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Subject: Docket No. 50-206
Systematic Evaluation Program
San Onofre Nuclear Generating Station
Unit 1

Your letter of February 9, 1979 forwarded to Southern California Edison (SCE) a draft assessment of "SEP Review of Safe Shutdown Systems for the San Onofre Unit 1 Nuclear Power Plant." Enclosure 1 of this letter contains comments on the draft assessment.

Since the assessment was written, the events at Three Mile Island have resulted in several changes to both the San Onofre Unit 1 hardware and procedures. Several procedures are referenced in the assessment. Revised copies of those procedures are provided in Enclosure 2 of this letter. Hardware changes have been made to the Auxiliary Feedwater System, and more are planned. Enclosure 3 of this letter provides drawings of the existing auxiliary feedwater system configuration and the planned changes.

If you have any questions, please let me know.

Very truly yours,

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J G Haynes

J. G. Haynes
Chief of Nuclear Engineering

Enclosures

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Enclosure 1

Comments on SEP Review of Safe Shutdown Systems
for San Onofre Nuclear Generating Station Unit 1
SEP Topics V-10.B, V-11.A, V-11.B, VII-3, X

1. Page 2, paragraph 1. Hot standby conditions are $525^{\circ}F \leq T_{ave} \leq 540^{\circ}F$. Cold shutdown conditions are $T_{ave} \leq 150^{\circ}F$.

2. Page 6, paragraph 1. The flash evaporator is removed from service before reaching 33 1/3% power (150 MW_e).

3. Page 10, item 6 add:

   "except when trip is from electrical protection or remote turbine trip push button (see next paragraph)."

4. Page 11, paragraph 2. Rewrite the first sentence as follows:

   "Prior to the cooldown, it is determined that the boric acid and primary makeup water systems have enough capacity to compensate for the reactor coolant shrinkage."

5. Page 11, numbered procedure steps. Add as Step 1:

   "1. Borate the Reactor Coolant System to the cold shutdown concentration in accordance with approved instructions." Renumber the remaining steps accordingly.

6. Page 13, paragraph 1. The normal operating pressures for the various cooling systems are:

RHR	80 to 420 psig	(465 max)
CCW	65 to 75 psig	(80 max)
SWC	30 psig	(50 max)

7. Page 13, Section 2.2, paragraph 2, second sentence. Delete the phrase "When buses 1C and 2C are energized with diesel power" since the steam driven auxiliary feedwater pump should be used if a delay is experienced in re-establishing station power.

8. Page 14, paragraph 1. Operating Instruction S-2-13 Rev. 10, Auxiliary Feedwater System Operation, provides for aligning alternate water sources as required.

9. Page 14, paragraph 2. As stated in the assessment, the 6000 kW diesel/generator units supply adequate power to bring the unit to cold shutdown in a "normal" manner. Step 4.11 of O.I. S-3-5.30 Rev. 10, instructs the operator to place the unit in the appropriate condition. No special instructions are required because of the loss of offsite power.

10. Page 16. Footnote. The footnote is ambiguous and should be clarified, perhaps with a reference to Section 3.2, Steam System ASME Code Safety Valves.

11. Page 17, paragraph 1. Not all equipment on Table 3.1 should be "safety grade". Since Table 3.1 is included entirely in SEP Topic III-1, it would simplify the bookkeeping if Table 3.1 were deleted from this review and a reference made to Topic III-1.

    Comments on the information included on this table were forwarded separately as part of SCE's review of Topic III-1.

12. Page 18, list of minimum systems.

    1. Steam system ASME Code safety valves - the MSSVs are redundant equipment for the ADVs and SBVs. The ADVs and SBVs are designed to preclude MSSV actuation. On loss-of-offsite power, the ADVs and SBVs open on turbine trip. For loss of compressed air supply, the ADVs and SBVs are supplied with enough air (via local air receivers) to operate at least once. Air supply can be restored by either the diesel driven air compressor or the station emergency air compressor.

    4. Water sources - To be consistent with the Technical Specification, the sources should be:

        condensate storage tank and primary plant makeup tank and/or service water reservoir.

    11. Chemical and Volume Control System - only the charging and letdown portions of the CVCS are required for "minimum" equipment. This should be clarified on the minimum equipment list.

13. Page 18, footnote. The pressurizer heaters are not required to stay at hot shutdown for four hours. Therefore, the footnote should be deleted and the heaters should not be included in the minimum list.

14. Page 19, <u>Discussion</u> - The ADVs and SBVs are designed to prevent actuation of MSSVs. Decay heat is normally removed by the ADVs and/or SBVs and the MSSVs act as backup and open only if ADVs/SBVs fail or have insufficient capacity.

15. Page 20, paragraph 1. The total relieving capacity of each steam line should be 3,143,695 lbm/hr (5 x 628,739 lbm/hr) since all valves, regardless of their set point, will have at least 1035 psig back pressure when all relief valves are open. This results in a total capacity of 6.28×10^6 lbm/hr for both steam lines. Immediately after loss of AC and scram, steam generator pressure is controlled by the SBVs (to the condenser) and the four ADVs. The MSSVs are redundant equipment for these valves. See Comment 12, Item 1.

16. Page 20, paragraph 2. The MSSVs are redundant equipment for the ADVs and SBVs. The ADVs do have sufficient capacity to preclude MSSV actuation on loss of load.

17. Page 21, paragraph 1, last sentence. Since only 1 MSSV is required to control steam generator pressure, the failure of 1 MSSV would not be unacceptable because of the redundancy provided by the other nine MSSVs.

18. Page 23, last paragraph. A full open signal is developed when the controller is in "Temperature: Automatic" and there is $\geq$ 10% decrease in turbine load and Tave-Tref $\geq$ 12°F.

19. Page 24, paragraph 1. Delete "at least" from the first sentence. Change the last sentence to read:

    "Although the SBVs, condenser, condensate pumps and feedwater pumps are not part of the "minimum systems", they are mentioned here because they provide redundancy beyond that provided by the four ADVs."

20. Page 24, paragraph 2. The steam jet air ejectors do not remove energy from the system by rejecting heat to the environment, but are cooled by the condensate flow returning to the steam generators. Therefore, the air ejectors should be deleted from this discussion except with regard to the requirement for use of SBVs.

21. Page 25, paragraph 2. The steam driven auxiliary feed pump turbine uses 8100 lbm/hr steam at 600 psig inlet and 5 psig back pressure.

    This paragraph implies that the motor-driven AFP is preferred. Either pump may be used at the operator's option.

22. Page 25, Table at bottom of page. For the ADV and SBV, the table should be clarified to indicate RCS energy removal rate is per valve, and that the time at which these systems can provide adequate relief is somewhat shorter than that shown if more than one valve is used.

23. Page 27, paragraph 4. Change title to:
    "Turbine and Motor Driven Auxiliary Feed Pumps"

24. Page 27, paragraph 4. Add to the sentence describing Task, "and the feedwater system is inoperable."

25. Page 28. Add to the table under "Power Supply" for the ADVs, SBVs and SDCS, "Compressed Air System."

26. Page 28. The steam jet air ejectors are near the south condensate pumps. The control room SDCS is located on the J panel.

27. Page 29, paragraphs 2, 3 and footnote. Normal steam generator water inventory at full power is 38,760 lbm per steam generator. The initial steam generator inventory is sufficient to maintain hot shutdown for at least 30 minutes, not 25 minutes.

    The assumption of 15 second delay before reactor scram is overly conservative. Reactor scram would occur immediately on turbine/generator trip and/or primary coolant pump breaker open.

28. Page 30, paragraph 1.

    a. Either or both AFPs can supply water through the normal or emergency auxiliary feedwater flow paths.

    b. The 4" valve (4"-600-140) is normally open. The three 3" valves (3"-600-139) in the emergency auxiliary feedwater lines are normally closed and must be manually opened to supply feedwater through the emergency line.

    c. Control of auxiliary feedwater through the emergency lines is by manual positioning of the 3"-600-139 valves in each line.

    d. The FRVs (FCV 456, FCV 457 and FCV 458) fail open on loss of air.

29. Page 30, paragraph 2. Isolation of failed portions of the AFP flow paths can be accomplished by manual valves, motor operated valves, air operated valves and check valves.

30. Page 31, pagagraph 1.

    a. MOV-1204 may also be used to isolate portions of the auxiliary feedwater flow path.

    b. Closure of HV-852A and HV-852B would isolate portions of the feedwater system from the auxiliary feedwater flow path, but would also isolate the feedwater system from the steam generators.

31. Page 31, paragraph 1. Valves 852A and 852B are hydraulically operated. MOV-20, 21 and 22 can also be used to isolate portions of AFS piping.

32. Page 31, paragraph 2. The condensate makeup/reject line from the condensate storage tank is a 14" line (721-14"-HP). The auxiliary feed pump suction line from 721-14"-HP is a 4" line (380-4"-HP). Failure of either line would render both AFPs inoperable. However, if either line should fail, indication of the failure in the control room would be:

    a. decreasing steam generator level (LI-450X, LI-451X, LI-452X)

    b. no auxiliary feedwater flow indication (FI-2002A, FI-2002B, FI-2002C or FI-2004A, FI-2004B, FI-2004C)

33. Page 31, paragraph 3. Chang permits the depressurization" to "would result in depressurization."

34. Page 32, paragraph 2.

   a. It is planned to change the operation of the auxiliary feedwater pumps to automatically start on low steam generator level or by remote manual operation in control room.

   b. CV-113 can be opened and controlled manually so that air is not required to operate the turbine. The diesel-driven air compressor system is also available to supply air pressure.

35. Page 32, paragraph 3. The motor-driven AFP is designed to deliver 235 gpm at a dischai ;e of approximately 2450 feet (1060 psig).

36. Page 32 footnote. Sequencer does not automatically perform breaker alignment on loss-of-offsite power. Breakers are manually aligned.

37. Page 33, paragraph 1. The flow rate fo. the motor driven auxiliary feed pump is 235 gpm. This is sufficient to control and raise the steam generator level at approximately seven to eight minutes after reactor scram. The turbine driven auxiliary feedpump flow rate is 300 gpm and is sufficient to control and raise steam generator level after three to four minutes.

38. Page 34, paragraph 3, Item 4. The normal hotwell makeup line is 10" to 12" to 8" branch.

39. Page 35, Table.

   Delete "3" AFP Isolation Valves" and add:

Equipment	Location	Operation	Power Supply
MOV-1204	Turbine building next to AFP G-10	Remote manual switch in control room	480V SWGR #2
3"-600-139 (3 valves)	Between CS and north end of the turbine building	Local manual only	None

   The "4" Isolation Valve" in the emergency flow path is normally open and does not need to be moved for auxiliary feedwater system operation.

40. Page 36, paragraph 4. a) The fire hydrants have been renumbered. Hydrant #6 is now #9 and #7 is now #10. b) The 3" nipples are on the tank drain and fill lines, not on the overflow. Therefore, footnote ## should be deleted. c) The comment made in footnote # is no longer applicable, as designated fittings, hoses and wrenches are now provided.

41. Page 36, Footnote *. The normal makeup for the SWR is city water.

42. Page 38, paragraph 2. A condensate pump may be powered from the emergency diesel/generator(s) following a loss of off-site power. This would allow condensate in the hotwell to be utilized for plant shutdown.

43. Page 39, paragraph 4. It should be noted that RHR performance stated here is for both pumps and heat exchangers in operation. Degraded RHR operation is acceptable but will result in longer cooldown times. Normal RHR cut in is at 350 psig; 400 psig is maximum allowable.

44. Page 40. FH-6 is now FH-9 and FH-7 is now FH-10. FH-10 is in the Southwest corner next to the heater deck. FH-9 is located south of the turbine building. Delete the table entry "Portable Fire Hoses and Fittings."

    The Main Condensate Pumps and Main Feed Pump power supply is 4160V, not 2400V.

45. Page 41, paragraph 1. Insert after the word "temperature", "(one pump and one heat exchanger)."

46. Page 42, paragraph 2. Delete "bypass" from the third line. The primary method of controlling cool down rate is by throttling HCV602.

47. Page 42, Footnote. The footnote is not correct. The heat removal rate of 16.1×10^6 BTU/hr per heat exchanger is based on conditions of RCS temperature of 140°F and not 350°F, as shown in line 1 of table on page 44. Line 2 of that table indicates a total heat removal rate of 141×10^6 BTU/hr, well in excess of 0.8% power.

    Page 44, Table. For 2 RHR pump/1 Hx operation, the shell inlet temperature has a typographical error (1192°). This should be corrected.

48. Page 46, paragraph 2.

    a. If any one of MOV-813, MOV-814, MOV-833 or MOV-834 fails to open, the RHR is rendered inoperable. However, these valves are also equipped with hand wheels, which would allow the valve to be opened manually if the motor operator or power supply failed.

    b. The CVCS can be used in a "feed and bleed" mode to cool the reactor core with the vessel head in place.

49. Page 47. RCS/RHR MOVs are operable from the control room, at the breaker and manually at the valve by hand wheel.

50. Page 48, paragraph 1. Add charging pump oil coolers to CCW heat loads.

51. Page 48, paragraph 2. The CCW surge tank is connected to both the suction and discharge of the CCW pumps. Makeup for the CCW is from the primary plant makeup water.

52. Page 49, paragraph 4. The first sentence is true only for the letdown mode.

53. Page 50, paragraph 1. Operation of all three pumps and both heat exchangers is not required, but is preferred.

54. Page 51, paragraph 2 through Page 53, paragraph 1. The calculations of the maximum heat removal capability of the CCW system considering various equipment configurations and throttling of the CCW from the RHR heat exchangers have not taken into account the 200°F maximum CCW temperature and 120°F limit on water to RCP bearing coolers. Throttling CCW flow from the RHR heat exchanger does not significantly reduce CCW pump flow (flow through the CCW heat exchangers) since the RHR heat exchanger is a parallel load to the other CCW loads. Therefore, throttling would reduce flow through the RHR heat exchanger and increase flow through the parallel loads, keeping CCW flow roughly unchanged.

The table on Page 52 should be redone to show the total heat removal rate of the CCW without exceeding the 200°F/120°F limits. SCE has estimated this capability and those estimates are shown below. The assumptions made are:

a) Mean saltwater temperature is 80°F.

b) CCW flows for various equipment configurations are the same as the staff calculated.

c) CCW heat exchanger heat transfer coefficients do not change with temperature and are calculated using assumption a) and staff calculated temperatures and total heat transfer rates.

CCW Pumps/ HXS	Total CCW Flow	T_1	T_2	Total Heat Removal Rate
3/2	2.22×10^6 lb/hr	177	120	126×10^6 Btu/hr
2/2	1.60×10^6	194	120	118×10^6
2/1	1.40×10^6	153	120	46.2×10^6
3/1*	1.90×10^6	147	120	51.3×10^6

*SCE assumed that the third CCW pump could be started without over-pressurizing the system, or violating any other system limits.

In all cases, no system temperature limits were exceeded and the total heat transfer rate is greater than the decay heat at four hours. Hence, the RHR system can be placed on-line 4 hours after scram and the RCS cooled down, even with the most limiting failure in the CCW system.

55. Page 54. Add MOV-720A, MOV-720B, TCV-601A and TCV-602B to the table.

56. Page 55, paragraph 2. There is a cross-tie line between 415-12"-KPI and 416-12"-KPI such that either or both heat changer(s) (E-20A or E-20B) may be cooled by flow from any combination of SWCP G-13A, G-13B and the ASWCP.

57. Page 56. Add the emergency air compressor to discussion.

58. Page 57 table. All equipment is operable from the switchgear room. Bus 1C and Bus 2C are 4160V. The screen wash pumps are operable locally at the pump. The auxiliary SWCP is located outside, west of the pump well, next to the tsunami wall, and is operable from the control room or its power supply (SWGR-3, 480V).

59. Page 59, paragraph 1. The SBVs are susceptible to the same single passive failure (failure of the air headers) as the ADVs. Air connections have been made to use the diesel-driven air supply.

60. Page 59, Footnote - the hookups have been made. Delete "and time schedule" from the second sentence.

61. Page 60, last paragraph and footnote. The boric acid tank (BAT) and boric acid transfer pump (BATP) are not required to borate the RCS for cold shutdown. The boron concentration in the RWST is sufficient to borate the RCS for cold shutdown conditions. Therefore, the required equipment for the CVCS is the RWST, charging pumps and associated piping, valves, fittings and instruments.

62. Page 60, paragraph 4.

    a. Either or both of the RHR heat exchangers can be used to cool letdown flow.

    b. If the RWST is used as the water supply for the CVCS, no other boration equipment is required.

63. Page 61. The air receivers are outside, just north of the CST. Air compressors are operable from the switchgear room.

64. Page 63, paragraph 3. The Tech Spec limits for the RWST are a minimum of 240,000 gallons of water with a boron concentration between 3750 ppm and 4300 ppm.

65. Page 66. The CVCS test pump is listed in the table but is not addressed in the system evaluation. It should be included in the Discussion and Redundancy.

66. Page 66. There are no heaters in the Refueling Water Storage Tank. The power supply for the Boric Acid Tank heaters and heat tracing is MCC 1.

    The Boric Acid Tank (BAT) is filled by local manual valve alignment and operation of the BATP thru CV-333. CV-333 is air operated. The BATP is powered from 480V MCC-1.

67. Page 84, paragraph 2. 330°F should be 350°F.

    422 psig should be 400 psig.

68. Page 85, paragraph 2. The volume of the PRT is 8500 gallons with normal level of 6800 gallons.

69. Page 85, paragraph 2. The two containment sump pumps should be used to drain the sump, not the SIS recirc pumps, since sufficient NPSH would not be available.

70. Page 86, paragraph 1. If one RHR pump were operating, RHR flow to the RCS would decrease and the low flow alarm would alert the operator. However, if both RHR pumps were running, no low flow alarm would result since RHR flow to the RCS would be approximately 1557 gpm (2 x 1170 - 783 = 1557) and the alarm is set at 1000 gpm.

71. Page 86, paragraph 1. Insert after "containment floor", "not designed for submerged operation."

72. Page 86, Evaluation - To be consistent, "RHR" should be used instead of "SCS".

73. Page 87, paragraph 3. If any one (or any combination) of valves MOV-813, MOV-814, MOV-833 or MOV-834 were shut, the 3/4" recirc line would provide minimum flow to the RHR pumps. RHR Pump G14A is now equipped with a 2" (5056-2"-S2) recirc line. The 3/4" recirc line would pass less than 1000 gpm and the low flow alarm would alert the operator to system misalignment.

74. Page 90, paragraph 1. To adequately document review results, the basis for believing that adequate boron mixing occurs should be given.

75. Page 93, paragraph 2. Section 4.2 does not state that the RHR relief valve does not provide sufficient relief capacity to protect the RHR system from overpressure by the most severe postulated transient.

76. Page 100, paragraph 1, 2 and 3. As noted in previous comments, the auxiliary feedwater system is being modified to provide for both automatic initiation and remote (control room) operation.

77. Page 101, paragraph 2. As part of the auxiliary feedwater system modification, additional instrumentation, namely auxiliary feedwater flow, has been added to the system and would allow the operator to detect an abnormal auxiliary feedwater system condition. These changes are shown in Enclosure 3 of this letter.

78. The following is a list of typographical errors:

Page	Line	Currently	Should Be
8	16	withdrawal	withdrawn
20	2	10^9	10^6
25	13	p = 100 psig	P = 1000 psig
25	Last	650×10^5	6.50×10^5
27	12	"be" is omitted after "may"	
28	1	Delete "Dump"	
28	7	SDSC	SDCS
36	6	these	there
36	17	from	for
36	19	fir	for
37	9	houses	hoses
44	9	effect	affect
45	3	PP_o	P/P_c
47	11	776-4"-754	776-4"-T54
51	9	delete the comma	
57	5	G435	G43S
57	5	48)	480
59	12	EDVs	EDGs
62	15	steam	stream
66	20	elution	elevation

Enclosure 2

Revised Operating Instructions
San Onofre Nuclear Generating Station
Unit 1

	Operating Instruction	Revision No.	Title
1.	S-3-1.4	9	Unit 1 Shutdown to Hot Standby Condition
2.	S-3-5.1	7	Emergency Shutdown
3.	S-3-1.5	14	Plant Hot Shutdown to Cold Conditions
4.	S-3-5.28	7	Forced Evacuation of Control Room due to Fire Causing Loss of All Station Power and/or Normal Instrument Air
5.	S-3-5.30	10	Station Loss of Off-Site Power
6.	S-2-13	10	Auxiliary Feedwater System Operation
7.	S-3-1.13	5	Reactor Shutdown From Hot Standby to Hot Shutdown

Enclosure 3

Preliminary Design of Modifications
to the Auxiliary Feedwater System
San Onofre Nuclear Generating Station
Unit 1

1.	Drawing 451283	Control Block Diagram Auxiliary Feedwater Automatic Initiation
2.	P&ID 5159570	Auxiliary Feedwater
3.	P&ID 568773	Main Steam System

(1)

UNIT 1 SHUTDOWN TO HOT STANDBY CONDITION

I. OBJECTIVE

To shut down Unit 1 from full load or any intermediate load to a hot standby condition of the primary plant and secondary plant to a generator-off-the-line, full vacuum, steam dump control of main steam at 930 psig condition.

II. CONDITIONS

A. Unit I is on the line at any electrical load.

B. The nuclear instrumentation: startup, intermediate, and power channels shall be operating normally or in a ready-to-operate condition.

C. Auxiliary systems are in service as required for hot standby conditions.

III. PRECAUTIONS

A. Any plant changes which produce a sudden change in reactor coolant temperature of the order of 10°F or in reactor coolant boron concentration of the order of 10 ppm must be avoided.

B. Xenon level variations must be anticipated following a load decrease and boron concentration changes made as required to maintain the control group in the normal operating band.

C. Whenever reactor power is greater than or equal to 10% full power, three (3) reactor coolant pumps shall be in operation. Whenever reactor power is less than 10% of full power, operation with less than three (3) reactor coolant pumps operating shall be limited to less than 24 hours; except during low power physics testing. (Conducted below 5% of full power.)

D. The steam generator water levels should be manually controlled when in the hot standby condition and maintained at 50% level as indicated on the narrow range recorders to prevent the feedrings from being uncovered.

E. Failure to place the feedwater controls on manual prior to tripping the turbine stop valves may result in a large volume of feedwater being added to the steam generators. This could result in cooldown of the reactor coolant.

F. Isotopic analysis for iodine in the reactor coolant must be made between 2 and 6 hours following a thermal power change exceeding 15% within a one hour period.

IV. CHECK-OFF LIST (Not Applicable)

V. INSTRUCTIONS

IMPORTANT STEPS	KEY POINTS
1. Inform System Dispatcher and Switching Center the unit is ready to reduce load, estimated time of going off the line, and the rate of load reduction.	1. The Dispatcher and Switching Center should be informed as far in advance as practicable when preparing to take the unit off the line.

IMPORTANT STEPS	KEY POINTS
2. Reduce load on the unit.	2. a. Mark charts as per O.I. S-12-11.
3. On load reduction, observe alarms and recorder indications.	3. a. Alarm "Alert-Switch NIS Mode of Operation to Mid-Range". b. Change mode of operation switch from High to Mid.
4. At less than 70% load, remove reheater steam dump system from service.	4. See Operation Instruction S-9-2.
5. Remove flash evaporators from service.	5. Refer to O.I. S-2-5.
6. Borate as necessary to keep control rods above shutdown margin.	
7. Unit at 33% of full load.	7. a. Observe operation of reheater controls. b. 125°F/hr. maximum rate of temperature change on crossover
8. Unit at 20% of full load. a.	8. a. (1) Transfer reactor overpower mode of operation from Mid to low position. (2) Transfer rod control from automatic to manual. (3) Transfer feedwater to manual control and slowly increase level to 50% as indicated on the narrow range recorders. (4) Transfer steam dump mode switch from automatic to pressure control at 930 psig set point.

IMPORTANT STEPS	KEY POINTS
8. (continued)	8. (continued)
	a. (5) Open turbine drain valves and extraction trap bypasses.
b. Transfer 4160 volt bus 1A and 1B from the unit auxiliary transformers to station auxiliary buses 1C and 2C (refer to O.I. S-6-5).	b. (1) If the 220 kv and 138kv switchyards are connected, transfer by parallel operation. (2) If the 220kv and 138kv switchyards are not interconnected, transfer by drop and pickup operation.
c. Stop heater drain pumps	
9. Reduce unit load to minimum on load limit.	9. a. Under manual control, insert control rods to maintain avg Tavg between 535° and 540°F. b. Verify that steam dump or pressure control is regulating for a stable reactor power level.
10. Below 10% of full load, reduce feedwater pump and condensate pump requirements	10. Stop a feedwater pump and a condensate pump.
11. Start turbine auxiliary oil pump.	
12. Notify Dispatcher and Switching Center that unit is ready to take off the line.	12. a. The Dispatcher and Switching Center should be informed of status of unit. The Dispatcher gives permission to take unit off the system. b. Take the power system stabilizer and voltage regulator out of service.

IMPORTANT STEPS	KEY POINTS
12. (continued)	12. (continued)
	c. If turbine tests are planned, remove unit from line by opening unit PCB's.
	d. If no tests are planned, reduce steam flow to zero and allow unit to be removed from service by no-load and anti-motoring circuits.
13. Turbine-generator on turning gear.	13. a. Verify unit automatically on turning gear, and field breaker open.
	b. Lube oil cooling set points changed from 115°F to 85°F.
	c. Turbine hood sprays on temperature control.
14. Complete switching to provide an alternate source of auxiliary electrical power.	14. a. Notify Switching Center of switching procedure.
	b. Check open Unit 1 PCB's and 4160V ACB's 11A04 and 11B04.
	c. Open the generator motor operated disconnect.
	d. Close unit PCB's
15. Maintain reactor nuclear power level <10% of full load power.	15. a. Adjust reactor makeup control to automatic at reactor coolant boron concentration for leakage requirements.
	b. Periodically initiate pressurizer spray flow to adjust boron concentration.
* 16. Reduce primary and secondary plant auxiliary requirements.	a. Mark charts as per O.I.S-12-11.

VI. FINAL CONDITIONS

The final conditions of hot standby are:

A. The reactor power level is being maintained by manual control of the controlling group of rods at <10% of full power by observing the nuclear intermediate channels and maintaining Tavg between 525° - 540°F. The pressure control of the main coolant will be automatically controlled and maintained at 2085 psig.

B. Secondary plant (turbine-generator and auxiliaries) is in a hot standby condition with the unit on turning gear, steam seals on, normal vacuum, steam generator levels manually controlled at 50%, and a minimum number of auxiliaries in operation. An alternate source of auxiliary electrical power is available.

R. R. Brunet
R. R. BRUNET
SUPERINTENDENT UNIT 1

APPROVED:

J. M. Curran
J. M. CURRAN
PLANT MANAGER

JER:sel

*Indicates revision