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C-E GUIDELINES
AND OPERATING PLANT PROCEDURES
INDEX

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Roisman 79-58

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EMERGENCY PROCEDURE GUIDELINES

LOSS OF COOLANT ACCIDENT

NOTE
RCP trip

A loss of coolant accident is defined as a breach of the reactor coolant system boundary which results in the interruption of the normal mechanism for removing heat from the reactor core.

A. SYMPTOMS

1. Reactor coolant leak rate exceeds the capacity of the operable charging pumps.
2. Any one or more of the following indications or alarms may be present:
   a. Safety injection initiation
   b. Low pressurizer level
   c. High containment sump level
   d. High containment radiation level
   e. High containment pressure
   f. Containment isolation
   g. Thermal margin/low pressure trip
   h. Low pressurizer pressure
3. Indications of a reactor trip.

B. IMMEDIATE ACTION

1. Trip the reactor and turbine if not already tripped, and carry out N-EP-1.
2. Initiate safety injection if not already initiated.
   The following equipment should be in the condition indicated:

a.	2 HPSI pumps	ON
b.	2 LPSI pumps	ON
c.	3 Charging pumps	ON
d.	2 Boric Acid pumps	ON
e.	3 RBCCW pumps	ON

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B. 2. f. 8 HPSI valves OPEN
g. 4 LPSI valves OPEN
h. 4 Check valve leakage control valves SHUT
i. Volume Control Tank isolation valve SHUT
j. 3 Service Water pumps ON
k. 2 Diesel generators ON
l. 2 Boric acid tank recirculation valves SHUT
m. 2 Boric acid pumped feed stop valves OPEN
n. Boric acid pumped feed stop valve OPEN
o. Makeup stop valve SHUT
p. Letdown stop valves SHUT

3. Ensure ~~containment isolation~~ if conditions warrant.
4. Secure all reactor coolant pumps.
5. Deenergize all pressurizer heaters.
6. Verify proper operation of the safety injection system. by observing flow rates and safety injection tank levels.
7. Carry out the applicable site emergency plan.

C. SUPPLEMENTARY ACTION

1. If Containment Spray Actuation signal is received, insure the following:

a. 2 Containment spray pumps ON
b. 2 Containment spray isolation valves OPEN

2. If recirculation actuation signal is received, insure the following:

a. 2 Containment sump isolation valves OPEN
b. 2 LPSI pumps OFF
c. 2 HPSI pumps ON
d. 2 Containment Spray Pumps ON

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C. 3. After verifying that the containment sump isolation valves are open and recirculation is occuring, close the RWT isolation valves and mini-flow header valves.

4. Maintain normal water level in the steam generators.

5. Check reactor coolant relief valves, safety valves, and quench tank for leakage.

6. Initiate action to limit the spread of contamination.

7. Ensure availability of Shutdown Heat Exchangers.

EMERGENCY PROCEDURE GUIDELINES

REACTOR TRIP

Note no PORV isolate vital bus

A. SYMPTOMS

1. Any one or more of the following trip alarms are present:
   a. Manual reactor trip
   b. High power level trip
   c. Thermal margin/low pressure trip
   d. Low flow trip
   e. High pressurizer pressure trip
   f. Low steam generator pressure trip
   g. Low steam generator level trip
   h. High rate of change of power trip
   i. Loss of load trip
   j. High containment pressure trip
   k. Axial shape trip
2. Turbine trip
3. CEA lower electrical limit lights on
4. CEA position indication shows all CEA's (except part length CEA's) on the bottom

B. IMMEDIATE ACTIONS

1. Ensure all full length CEA's are fully inserted (initiate manual trip if not) and reactor power is decreasing.
2. Ensure turbine has tripped and generator breaker has opened. Manually trip if not.
3. Ensure the following automatic functions have occurred. Initiate any that have not.
   a. Steam dump and bypass valves controlling steam generator pressure at 900 psia.
   b. Feedwater flow is reduced to 5% of full load flow.

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I. 3. c. Pressurizer power operated relief valves open (ON HIGH PRESSURE TRIP ONLY).

d. Main steam isolation valves shut (ON LOW STEAM GENERATOR PRESSURE ONLY).

e. Safety injection is initiated (ON HIGH CONTAINMENT PRESSURE OR LOW PRESSURIZER PRESSURE ONLY).

f. Emergency diesel generators starts on SIAS or 4160 V bus under voltage.

4. Ensure at least two reactor coolant pumps are operating - preferably RCP 1A and/or 1B.

5. Ensure proper pressurizer level is being maintained; take manual control if necessary.

6. Ensure transfer of unit loads to Reserve Station Service Transformer.

J. SUPPLEMENTARY ACTION

1. Take necessary actions to maintain or regain zero power reactor coolant system parameters (temperature, pressure, and pressurizer level). If the RCS can not be maintained, shut the main steam isolation valves.

2. Ensure steam dump valves close as T_{avg} approaches 532°F.

3. Shift feedwater control to the bypass and maintain steam generator level in the normal band.

4. If condenser vacuum is lost, ensure that steam generator pressure is being maintained with the atmosphere steam dump.

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5. If safety injection has actuated, ensure normal automatic operation, and restore system to normal after reactor is safely shutdown.

6. If steam generator safeties lifted check for proper reseating. If leakage is excessive, prepare to borate and to shut the plant down.

7. If pressurizer power operated relief valves operate, ensure proper quench tank status and subsequent reseating of the relief valves.

8. Determine cause of reactor trip and correct.

EMERGENCY PROCEDURE GUIDELINES

STEAM LINE RUPTURE

NOTE
RESET

A. SYMPTOMS

1. Decreasing steam generator pressure.
2. Fluctuating steam generator levels.
3. Rapid decrease in reactor coolant temperature and pressure.
4. Rapidly decreasing pressurizer level.
5. Any of the following alarms or indications may be present:
   a. Low steam generator level
   b. Low steam generator pressure
   c. Main steam isolation valves shut
   d. Low pressurizer pressure
   e. Reactor trip
   f. Containment high pressure
   g. Containment isolation
   h. Safety injection actuation

B. IMMEDIATE ACTION

1. Ensure the following automatic functions have taken place, initiate any that have not:
   a. Reactor trip
   b. Turbine trip
   c. Main steam isolation valves close.
   d. Feedwater flow is reduced to 5% of full load flow.
2. If low-low pressurizer pressure signals occur, ensure initiation of safety injection.
3. If high containment pressure signals occur, ensure initiation of safety injection and containment isolation.
4. If high-high containment pressure signals occur, ensure initiation of containment spray.
5. If the steam line rupture is upstream of the main steam isolation valve:

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5. a. Secure all feedwater flow to the affected steam generator.
   b. Secure all operating reactor coolant pumps in the affected loop.
   c. Maintain level in the unaffected steam generator.
   d. Maintain pressure in the unaffected steam generator as high as possible, but not to exceed 900 psia.
6. Start motor driven auxiliary feedwater pumps.

C. SUPPLEMENTARY ACTION

1. Restore water level in pressurizer and maintain in the normal band.
2. Borate Reactor Coolant System to shutdown boron concentration and proceed with plant cooldown. If the steam line rupture is upstream of the main steam isolation valve, use only the unaffected steam generator for cooldown.

NOTE RESET

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REACTOR COOLANT LEAK

NOTE DIAGNOSTICS (LIKE W DECISION TREE

1.0 SYMPTOMS

1.1 Charging flow (2FIS-4863 on 2C09) increases significantly above letdown flow (2FIS-4801 on 2C09).

1.2 Routine leak rate calculations (OP 2103.13) show greater than 1 gpm (unidentified) total RCS leak rate.

1.3 Excessive makeup to the VCT as indicated by BAMU flow totalizer (2FQI-4926 on 2C09) and RMW flow totalizer (2FQI-4927 on 2C09).

1.4 Leakage into CCW system:

1.4.1 Increasing CCW surge tank level (2LIS-5210/5214 on 2C14).

1.4.2 CCW radiation monitor alarm (2RE-5200/5202).

1.5 Leakage into SW system:

1.5.1 SW/SCS heat exchanger radiation monitor alarm (2RE-1453/1456)

1.5.2 SW/SF heat exchanger radiation monitor alarm (2RE-1525).

1.6 Backleakage into Safety Injection lines:

1.6.1 Increasing SI check valve leakage pressure (2PI-5000, 2PI-5020, 2PI-5040, and/or 2PI-5060 on 2C16/2C17.

1.6.2 Increasing SI tank level (2LI-5010, 2LI-5030, 2LI-5050, and/or 2LI-5070 on 2C16/2C17).

1.7 Leakage past the pressurizer relief valves.

1.7.1 Increasing pressurizer relief temperature (2TIS-4630/4631 on 2C04).

1.7.2 Increasing quench tank temperature (2TIS-4694), level (2LIS-4694), and pressure (2PIS-4694) on 2C04.

1.8 Leakage into containment:

1.8.1 Increasing containment sump level (2LIS-5641 on 2C33).

1.8.2 Increasing containment pressure (2PR-5604-1), temperature (2TR-5660), or moisture (2MR-5660) on 2C33.

1.8.3 Hydrogen purge/containment atmosphere radiation monitor alarm (2RE-8271-2/2RE-8231-2).

1.9 Leakage into Auxiliary building:

1.9.1 Increasing Auxiliary building sump level

1.9.2 Radwaste area ventilation radiation monitor alarm (2RE-8542).

1.10 Leakage into steam generator:

1.10.1 Steam generator radiation monitor alarm (2RE-5854/5864).

1.10.2 Main condenser air discharge radiation monitor alarm (2RE-0645/0646).

1.11 Leak in CVCS

1.11.1 Letdown isolation valve (2HS-4820-2) shuts on high temperature.

1.11.2 Abnormal and/or inconsistent ΔT's across the letdown side and charging side of the regenerative heat exchanger.

1.11.3 Abnormal letdown (2PIC-4812) and/or charging (2PIS-4870) pressure on 2C09.

1.11.4 Abnormal letdown (2FIS-4801) and/or charging (2FIS-4863) flow on 2C09.

2.0 IMMEDIATE ACTION

2.1 If the leak rate exceeds the capacity of the available charging pumps, TRIP THE REACTOR and carry out Loss of Reactor Coolant procedure, OP 2202.06.

2.2 Ensure that false leakage indications are not being caused by large generator load changes or by a change in Tavg.

2.3 Check that additional charging pumps are operating as necessary to maintain pressurizer level. Adjust makeup, if necessary, to maintain normal VCT level.

3.0 FOLLOW-UP ACTION

16.2 /4.4.6

3.1 Ensure that actions required by Tech. Spec. 3/4.4.6 (RCS Leakage) are performed.

3.2 Attempt to locate and isolate the source of RCS leakage based on symptoms 1.4-1.11.

3.3 Check the Auxiliary building and any accessible piping/components for visual signs of leakage.

3.4 If above actions cannot locate the leak, proceed as follows:

3.4.1 Shut the letdown isolation valve (2HS-4820-2 on 2C09). If pressurizer level increases, the leak is between the letdown isolation valve and the VCT.

3.4.2 Secure the running charging pump(s) and shut the loop charging isolation valves (2HS-4831-2 and 2HS-4827-2 on 2C09) and pressurizer charging isolation valve (2HS-4824-2 on 2C09) if open. If pressurizer level decreases at a rate associated with RCP bleed-off (4 gpm) the leak is in the charging lines or the VCT and its associated piping. If in addition, VCT level decreases, the leak is in the VCT and its associated piping only.

3.4.3 If pressurizer level continues to decrease more than that associated with RCP bleed-off, the leak is not in the CVCS; return CVCS to normal per OP 2104.02.

3.4.4 If feasible, make a containment entry to locate leak.

3.5 Seal off the affected area and initiate the Site Emergency Plan if required. Establish radiological controls in the leak area.

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NOTE RESETS, PUMP TRIPS

LOSS OF REACTOR COOLANT

CASE I - Rupture Greater Than Charging Pump Capacity(128 gpm)

1.0 SYMPTOMS

1.1 Rapid decrease in pressurizer level with maximum charging flow and little or no corresponding decrease in Tave or secondary pressure.

1.2 Increasing containment pressure, temperature humidity and sump level.

1.3 Reactor trip and engineered safety features actuation.

2.0 IMMEDIATE ACTIONS

2.1 Verify Reactor and turbine trip.

2.2 Verify proper ESFAS actuation, as follows:

2.2.1 Indicating lamps on ESFAS actuated components correspond to the color of the switch nameplates.

2.2.1.1 Red - Valve open or equipment running.

2.2.1.2 Green - Valve closed or equipment stopped.

2.2.2 Flows are within limits marked on meter faces.

2.3 Manually actuate ESFAS at limits below if automatic actuation does not occur.

2.3.1 SIAS & CCAS - Containment pressure $\geq$18.4 PSIA or pressurizer pressure <1740 PSIA.

2.3.2 CSAS - Containment pressure $\geq$23.3 PSIA

2.3.3 CIAS - Containment pressure $\geq$18.4 PSIA

2.3.4 MSIS - Steam generator pressure < 728 PSIA

2.3.5 RAS - RWT Level <5.5%.

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NOTE

If LPSI pumps do not trip upon RAS actuation, manually trip both LPSI pumps at handswitches on 2C16 & 2C17.

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3.0 FOLLOW UP ACTIONS

3.1 Trip RCPs.

3.2 Monitor HPSI, LPSI, and containment spray flows. If pressurizer level starts increasing, over-ride and close HPSI flow control valves one at a time to prevent the pressurizer from going solid.

> CAUTION
>
> Stop the HPSI pump prior to closing the last HPSI flow control valve in that train.

3.3 Maintain S/G's at normal levels utilizing the emergency feed system.

3.4 Shift S.W. Pump suction bays to the emergency pond.

3.5 At 5.5% in the RWT, verify RAS actuation by observing the following or perform the following:

3.5.1 Both LPSI pumps stop.

3.5.2 ECCS suction shifts to the containment sump. (Sump suctions 2CV-5649-1 & 2CV-5650-2 open and RWT outlets 2CV-5630-1 and 2CV-5631-2 Close).

3.5.3 ECCS component mini-recirc. valves to RWT shut.

3.6 At time 30 minutes after LOCA, stop all charging and boric acid pumps by placing their respective handswitches to "STOP" and "PULL TO LOCK".

3.7 At time 2-4 hours after LOCA, redirect HPSI flow to the RCS T_H via SDC suction by performing the following valve aligement:

3.7.1 Close 2CV-5103-1(2C-17) and 2CV-5104-2(2C-16).

3.7.2 Open 2CV-5101-1 and 2CV-5102-2.

3.7.3 Verify flow as follows:

3.7.3.1 Pump discharge flow meters(2FI-5101-2 & 2FI-5102-2) plus the T_C injection flow meters(2FI-5074-2, 5054-2, 5034-1 & 5014-1) are >500 GPM.

3.7.3.2 The difference between discharge and T_C injection flow is >250 GPM. This is indicative of T_H flow.

3.8 Within 24 hours after LOCA, initiate containment sampling per OP 2104.44.

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1.0 SYMPTOMS

1.1 Large pressurizer level deviation without a concurrent decrease in Tave.

1.2 Unexplained or excessive VCT makeup or level decrease in conjunction with high charging flow.

1.3 Increasing Containment Building Sump level.

1.4 Increasing Containment Building temperature, humidity, and activity levels.

2.0 IMMEDIATE ACTIONS

2.1 Verify that all Charging Pumps are running.

2.2 Isolate letdown by closing the Letdown Isolation Valve(2CV-4820-2). If pressurizer level stabilizes, the leak has been isolated in the Letdown System.

2.3 If pressurizer level continues to drop, trip the Reactor and open the RWT Supply to the Charging Pump Suction Header.

3.0 FOLLOW-UP ACTIONS

3.1 If the above actions stabilize pressurizer level, carry out loss of letdown OP 2202.50, otherwise proceed to Section I of this procedure.

3.2 Initiate cooldown per OP 2102.10(Plant Shutdown and Cooldown) at a rate that will maintain pressurizer level above the heater cutoff.

3.3 Conduct further operation as directed by plant management.

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POOR ORIGINAL

CASE III - SMALL LEAK

1.0 SYMPTOMS

1.1 Leak rate calculations show an increase in plant leakage.

1.2 Increase in Containment Building radiogas, particulate or humidity.

1.3 Excesssive or unexplained auto makeup to VCT.

2.0 IMMEDIATE ACTIONS

2.1 Check S/G Blowdown Radiation Monitors and condensers off-gas monitors to insure that a primary to secondary leak does not exist.

2.2 Verify that Pressurizer Level Control System is controlling pressurizer level at programmed level.

2.3 Attempt to locate and isolate leak.

2.4 Notify plant management.

3.0 FOLLOW-UP ACTION

3.1 Determine if leakage is from a primary boundary. If it is, take plant to Hot Standby within 6 hours per OP 2102.10, Plant Shutdown and Cooldown.

3.2 If source of leakage can not be determined and is greater than 1 gpm or if it is identified to be from other than primary boundary and is greater than 10 gpm, reduce leakage to within above limits within 24 hours or cooldown to Hot Standby within 6 hours.

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POOR ORIGINAL

EMERGENCY PROCEDURE
EP-1

Reactor Trip

BELIEVE,
1ANS75

A. PURPOSE

To describe the steps to be taken in the event that an automatic reactor trip occurs or in the event that the licensed operator(s) determine that the reactor must be shut down immediately.

The responsibilities and authorities of the licensed operators include but are not limited to the following:

1. The reactor operator's authority and responsibility for shutting the reactor down when he determines that the safety of the reactor is in jeopardy <u>or</u> when operating parameters exceed any of the reactor protection circuit setpoints <u>and</u> automatic shutdown does <u>not</u> occur.

2. The responsibility to determine the circumstances, analyze the cause, and determine that operations can proceed safely before the reactor is returned to power after a trip or an unscheduled or unexplained power reduction.

3. The senior reactor operator's responsibility to be present at the plant and to provide direction for returning the reactor to power following a trip or an unscheduled <u>or</u> unexplained power reduction.

4. The responsibility to believe and respond conservatively to instrument indications unless they are <u>proven to be incorrect</u>. !!!

5. The responsibility to adhere to the plant's Technical Specifications.

B. SYMPTOMS

1. Any one or more of the following alarms may be present:

   a. High containment pressure channel trip.

   b. High power level channel trip.

   c. Thermal margin/low pressure channel trip provided the zero power mode bypass is clear.

   d. Low reactor coolant flow channel trip provided the zero power mode bypass is clear.

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e. High pressurizer pressure channel trip.

f. Low pressure steam generator A or B, channel trip bypassed is clear.

g. Low water level steam generator A or B, channel trip.

h. High power rate of change channel trip provided the high power rate of change channel trip bypassed alarm is clear.

i. Loss of load channel trip with the Loss of Load Channel Trip Bypassed alarm cleared.

j. Axial power distribution channel trip provided the axial power distribution channel trip is not bypassed.

k. Automatic rod withdrawal prohibit alarm.

l. Turbine trip alarm.

m. Reactor trip alarm.

n. Generator breaker 3451-4 and 3451-5 trip alarm.

o. Generator lockout.

2. Any one or more of the following indications may be present:

a. Steam generator A and B pressure increasing.

b. CEA lower electrical limit lights.

c. CEA position indication shows all CEA's on the bottom.

d. Decreasing power level.

e. Feedwater flow ramp-down to 5% flow.

C. IMMEDIATE ACTION

1. Depress the manual reactor trip pushbutton. Ensure that all regulating and shutdown CEA's have been fully inserted and that reactor power is decreasing.

2. Ensure turbine has tripped and all stop and intercept valves are closed.

3. Ensure generator breakers 4 and 5 have tripped and that the generator field breaker has opened.

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D. FOLLOW-UP ACTION

1. Verify that pressurizer level has been reduced to and is being maintained at its no load value (48%). Verify that pressurizer pressure is being maintained.

   NOTE 1: If pressurizer pressure and level continues to drop as a result of continuing cool down of the RCS quickly proceed to Steps 2 and 3 below.

   NOTE 2: If pressurizer pressure and level continue to drop with no continuing drop in RCS temperature, suspect an RCS leak and reference EP-28 and/or EP-5.

2. Verify that both Main Feedwater Regulating Valves (FWRV) have "ramped" to 5% flow.

   NOTE: If this has not occurred automatically, take manual control of the FWRV(s) and close as required. If valves do not respond to manual control, secure main feedwater pumps and/or close FWRV block valves HCV-1103 and HCV-1104 and reference EP-6.

3. Verify that the steam dump and bypass system is controlling T_{AVG} and steam generator pressure at the no load condition.

   NOTE 1: If T_{AVG} and steam pressure are dropping below their no load values, take manual control and attempt to close the dump and/or bypass valves. If this is not successful in terminating uncontrolled heat extraction, shut MSIV(s) and reference EP-6.

   NOTE 2: If T_{AVG} and steam pressure have not been reduced to their no load values automatically take manual control of the bypass and/or dump valves and open as required. If this is not possible, open the atmospheric dump valve (HCV-1040) as required.

4. Ensure feedwater flow to both steam generators. If main feedwater flow is lost or is excessive, switch to the auxiliary feedwater system and secure the main feedwater pumps. Manual

   NOTE: If the auxiliary feedwater system is utilized, feed (preferred) into the main feedwater headers via HCV-1384 or via the emergency feedwater nozzles via HCV-1107 A/B and HCV-1108 A/B.

   CAUTION: Do not hesitate to utilize the emergency feedwater nozzle flow path if steam generator levels are not being restored by feeding via HCV-1384. Auxiliary feedwater flow to the main feedwater header will not get in the steam generators if one or more warm-up recirculation lines are open on the main feedwater pumps. ?

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D. FOLLOW-UP ACTION (Continued)

5. Verify that 4160 volt busses 1A1 and 1A2 have transferred to the 161 KV supply and that 4160 volt busses 1A3 and 1A4 continue to be supplied by the 161 KV feed.

   NOTE 1: If 1A1 and/or 1A2 bus fails to transfer automatically, RC-3A (1A1) and/or RC-3B (1A2) will be lost resulting in a partial loss of reactor coolant flow (reference EP-4).

   NOTE 2: If the 161 KV supply was lost, a total loss of off-site A.C. power has occurred (reference EP-3).

6. Ensure that required turbine generator lube oil auxiliaries are functioning.

   NOTE: The turbine oil lift pumps must be started prior to the turbine coasting down below 900 RPM.

7. Verify that both diesel generators have started.

   NOTE 1: Unless an accident signal (PPLS/CPHS) is present, the diesel generator auto start lock-out relays should be reset as soon as possible to restore diesel generator mechanical protection. The diesel auto start block-out relays cannot be reset until the Reactor Trip is reset and the 86-1/SVG1 and 86-2/SVG1 lockouts are reset.

   NOTE 2: The diesel generators may be shutdown as soon as the 161 KV <u>and</u> the 345 KV systems are available. The 345 KV system is deemed to be available as soon as DS-T1 has been opened and 345 KV power is available from either PCB-4 or 5.

8. Place the steam dump and bypass system AUTO-INHIBIT switch in the INHIBIT position and place the steam dump valve MAN/AUTO XFR and loading station in MAN at minimum setting.

9. Place the NI audible count rate circuit in operation to monitor for any changes in shutdown margin.

10. Verify that the Reactor is in at least a hot shutdown condition. This verification can be made by performing a shutdown margin calculation or by performing an ECP (Credit for Xenon/Samarium may be taken).

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11. Determine the cause of the trip and correct. (reference the POST TRIP REVIEW and sequence of events from the Plant Computer).

12. If RCS cool-down is required, verify and establish if necessary the proper shutdown margin taking no credit for Xenon or Samarium.

13. If re-start of the reactor is anticipated, reference OP-1 and OP-7.

E. DISCUSSION

1. The immediate action steps of this emergency procedure must be performed as quickly as possible and in the order indicated as soon as it has been determined that the reactor has tripped automatically or that the reactor must be tripped by the operator. Step 1 of the immediate action section ensures that the reactor is safely shutdown. Please note that Step 1 requires that the manual reactor trip pushbutton be depressed by the operator even though the RPS may have tripped the reactor automatically. Step 2 of the immediate action ensures that the turbine EHC system has tripped to secure steam flow to the turbine generator. Please note that it is extremely important to ensure that steam flow to the turbine is secured prior to opening generator output breakers PCB-4 and 5.

   NOTE: Lockout relays 86-1/SVG1 and 86-2/SVG1 ensure that PCB 4 and 5 open after steam flow is secured to the turbine automatically. To trigger these lockouts all four T.G stop valves must be closed and all inter[illegible]ate stop and intercept valves must be closed.

   Step 3 of the immediate action ensure[illegible] at the generator is disconnected from the grid after steam flow is secured to the turbine to prevent motorizing the unit. Step 3 also ensures that the generator field breaker has opened. A manual backup to Step 2 is depressing the EHC trip pushbutton on CB-10/11. A manual backup to Step 3 is tripping the control switch for PCB-4 and 5 and the generator field breaker at CB-20.

2. Follow-up Action Step 1 should be checked as soon as possible after the immediate action steps are completed. Pressurizer level and pressure abnormalities can alert the operator to:

   a. An u[illegible]led heat extraction, e.g., failure of a dump va[illegible] to reclose after unit trip or failure of a main feedwater regulating valve to ramp down can cause a rapid reduction in RCS temperature which in turn causes a rapid reduction in pressurizer level and pressure.

   b. An RCS leak.

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E. DISCUSSION (Continued)

3. The operator must then ensure that a safe hot shutdown condition has been achieved and can be maintained. The following factors are considered:

   a. A heat sink must be available for removing reactor decay heat and RC pump heat. Maintaining S/G water inventory is essential in this regard. Feedwater flow must be established to the S/G(s).

   b. Pressurizer level and pressure are maintained.

   c. RCS temperature is maintained.

   d. Adequate shutdown margin is and will be maintained.

550224

Keep RCP run

REACTOR TRIP

DISCUSSION: The intent of this procedure is to place the plant in a safe, HOT STANDBY condition. A reactor trip or "scram" is accomplished by rapid insertion of the control element assemblies (CEA's) into the core. Selected NSSS parameters are monitored and will automatically initiate a reactor trip if any one or a predetermined combination of the monitored parameters reach a Limiting Safety System Setting. R actor trips can also be manually initiated by operator action. The operator is alerted to a trip condition by reactor pre-trip alarms at the Plant Protection System (PPS) displays at 2C16. A reactor trip signal serves to de-energize the Contr l Element Drive Mechanism coils, allowing the shutdown, regulating and part length CEA's to drop into the core. Any one or more of the following conditions will cause a reactor trip:

- High Linear Power Level
- High Logarithmic Power Level
- High Local Power Density
- Low DNBR
- High Pressurizer Pressure
- Low Pressurizer Pressure
- Low Steam Generator Water Level
- Low Steam Generator Pressure
- High Containment Pressure
- Manual Trip
- High Steam Generator Water Level

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1.0 SYMPTOMS:

1.1 Annunciator alarms associated with any of the causes listed in the preceeding discussion.

1.2 All CEA bottom lights energized on the core mimic on 2C16.

1.3 All CEA's indicating fully inserted by CEA position display and digital indication.

1.4 Reactor reactivity, startup rate and power indicators show a rapid decrease.

1.5 "Reactor pretrip/trip" annunciator alarm at 2C16.

1.6 The remote trip status panel on 2C14 shows the trip circuit breakers (TCBS) have tripped open.

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2.0 IMMEDIATE ACTIONS:

2.1 Manually trip the reactor by depressing the two trip pushbuttons at 2C03 (2HS 9070-3, and 2HS 9071-2) or the two trip pushbuttons at 2C14 (2HS 9077-1 and 2HS 9078-4).

2.2 Verify that all CEA's are fully inserted, that reactor power is decreasing, and that the reactor trip switchgear breakers have opened.

2.3 Depress the turbine trip pushbutton at 2C01 and verify that the turbine has tripped.

2.3a Ensure that the following turbine valves are closed:

1. Main Stop Valves (2CV 0202, 0206, 0240, & 0250)
2. Control Valves (2CV 0203, 0207, 0242, & 0252)
3. Intercept Valves (2CV 0441, 0447, 0450, & 0500)
4. Intermediate stop valves (2CV 0442, 0448, 0451, & 0501)
5. Reheat Steam Source Valves (2CV 0400 & 0460)
6. Reheat Check Valves (2CV 0421, 0481)

2.3b Verify that generator output breakers 5130 and 5134 have tripped by observing the breaker status at 2C01 or 2C10.

2.4 Verify transfer of the 6.9 KV and the 4.16 KV buses from the Unit 2 Auxiliary Transformer to Startup Transformer 2 or 3 by observing the following breaker status:

2.4.1 Transfer to Startup Transformer 3

UNIT 2 AUXILIARY TFMR			STARTUP TFMR 3		
Bkr	152-14	OPEN	Bkr	152-15	CLOSED
Bkr	152-24	OPEN	Bkr	152-25	CLOSED
Bkr	152-112	OPEN	Bkr	152-113	CLOSED
Bkr	152-212	OPEN	Bkr	152-213	CLOSED

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2.4.2 Transfer to Startup Transformer 2

UNIT 2 AUXILIARY TFMR			STARTUP TFMR 2		
Bkr	152-14	OPEN	Bkr	152-13	CLOSED
Bkr	152-24	OPEN	Bkr	152-23	CLOSED
Bkr	152-112	OPEN	Bkr	152-111	CLOSED
Bkr	152-212	OPEN	Bkr	152-211	CLOSED

2.5 If a loss of all preferred power occurs verify the diesel generators start and are supplying ESF buses 2A3 and 2A4.

2.6 Verify that the main feedwater valves close and that the feedwater bypass valves are controlling at 5% of full flow.

2.7 Verify that both emergency feedwater system trains have automatically started and are operating satisfactorily in a post reactor trip mode and then secure one of the trains.

2.8 Refill the steam generators with normal (automatic) feedwater and the remaining (on-line) emergency feedwater pump until the downcomer water level is sighted in both steam generators.

2.9 Verify that TAVG is being reduced to the no load value (545°F) by operation of the SBCS.

2.9.1 If the main steam isolation valves have closed or condenser vacuum is lost, use the atmospheric dump valves to attain and maintain TAVG at 545°F (saturation temperature at 1003 psia).

2.10 Verify that the Pressurizer Level Control System is maintain level at the no load setpoint of 33% $\pm$ 1%.

2.11 Monitor reactor coolant system, steam generator, pressurizer, containment and radiation parameters and proceed if necessary to the applicable emergency procedure for:

2.11.1 Blackout - OP 2202.02

2.11.2 Loss of Reactor Coolant - OP 2202.06

2.11.3 Loss of Reactor Coolant Flow/RC Pump Trip - OP 2202.14

2.11.4 Steam Supply System Rupture - OP 2202.24

2.11.5 Loss of Steam Generator Feed - OP 2202.26

2.11.6 Radiological Incidents - OP 2202.35

2.11.7 Steam Generator Tube Rupture - OP 2202.23

3.0 FOLLOW-UP ACTION

3.1 Upon attaining indicated steam generator level, with the level rising, secure the remaining emergency feedwater pump and refill the steam generators with normal feedwater until downcomer water level is restored.

3.2 Ensure at least two RCP's are running (RCP1A and 1B should be running to provide pressurizer spray).

3.3 If necessary use manual control of the pressurizer heaters and/or spray to maintain primary system pressure at 2250 psia.

3.4 Carry out the follow up actions of 2202.03 - Turbine Trip.

3.5 If pressurizer safety valves lifted, monitor quench tank parameters and ensure that the safety valves have reseated.

3.6 If the steam generator atmospheric dump valves or reliefs have lifted, ensure that they have reseated.

3.7 Place the plant in HOT STANDBY in accordance with OP 2102.05 - Operation at HOT STANDBY.

3.8 If Technical Specifications, or other safety requirements require cool down, place the plant in a HOT SHUTDOWN condition in accordance with OP 2102.10 - Plant Shutdown and Cooldown.

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For: P. Bockhorst

EMERGENCY PROCEDURE FOR 2502

EMERGENCY SHUTDOWN (REACTOR TRIP)

Page No.	Effective Revision	Date
1	5	10/17/78
2	5	10/17/78
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5	5	10/17/78
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7	5	10/17/78
8	5	10/17/78

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1. OBJECTIVE

1.1 To provide a procedure to bring the plant to a hot shutdown condition after an emergency shutdown has been initiated automatically or manually by operator action.

2. DISCUSSION

2.1 Any shutdown of the plant accomplished by rapid insertion of the control elements (also called "Reactor Trip" or Scram") is considered an emergency shutdown. Emergency shutdown will be automatically initiated by the Reactor Protection System (RPS) whenever certain continuously monitored parameters surpass a predetermined setpoint. Emergency shutdown can also be initiated manually by operator action if unstable plant conditions warrant such action.

The operator is alerted to unstable plant conditions by several "Pretrip" alarms. Additionally, due to the fail safe nature of the RPS, a malfunction of the system can also cause an emergency shutdown.

A reactor trip occurring early in core life or after a prolonged plant shutdown leaves little decay heat to be removed. This creates the possibility of cooling the reactor coolant by the rapid insertion of feedwater (or addition of too much feedwater) to the steam generators following a reactor trip. This cooling could result in a reduction of shutdown margin. To help avoid this rapid over feed of water, the feed water regulating valves to the steam generators will automatically ramp down to a 5% open position and will then automatically go to manual control.

After an emergency shutdown the reactor may not be restarted until a Plant Incident Report (Station Form SF-1001) has been completed and all requirements of administrative control procedure ACP-QA-1.07 has been met.

3. SYMPTOMS OF EMERGENCY SHUTDOWN

3.1 Major Symptoms

3.1.1 All control element assembly (CEA) electrical limit lights on as indicated on core matrix. (C04)

3.1.2 CEA position indication shows all full length CEA's on the bottom as indicated by position step indicators and metrascope. (C04).

3.1.3 Reactor power indicators and recorders show rapid decrease in reactor power. (C04).

3.1.4 "Reactor Trip" annunciator alarm on panel C04 (red alarm light).

3.1.5 Annunciator drops verifying reactor trip circuit breakers (TCB's) (8) have tripped (C04).

3.1.6 Green indicating lights illuminated for TCB's (8)(C04).

3.2 Other Symptoms

3.2.1 Any one or more of the following annunciator alarms (red alarm lights) on panel C04.

		Approximate Trip Set Point
1.	Steam Generator Low Level	36.0%
2.	Steam Generator Low Pressure	500 PSIA
3.	Reactor Coolant Low Flow 4 pump Operation	91.7%
4.	Pressurizer High Pressure	2400 PSIA
5.	Thermal Margin/Low Pressure	Variable
6.	Nuclear Instrumentation High Power	Power Q
7.	Turbine Trip, Low Hydraulic Fluid Pressure	500 PSIG
8.	Local Power Density	Refer to Limit Lines of Tech. Spec. Figure 2.2-1 and 2.2-2.

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9. Containment High Pressure 4.75 PSIG

3.2.2 The reactor has been manually tripped because TAVG had decreased to less than 515°F for greater than 15 minutes.

3.2.3 The reactor has been manually tripped because of loss of one or more reactor coolant pumps.

3.2.4 The reactor has been manually tripped because number one and/or number two steam generator level has increased to 90%.

3.2.5 The reactor has been manually tripped because of a sustained start-up rate of 2.5 decades per minute.

3.2.6 The reactor has been manually tripped because number one and/or number two steam generator level has decreased to 45% with reactor power greater than 5%.

4. IMMEDIATE ACTIONS

4.1 Ensure the reactor has tripped by depressing the four (4) reactor trip pushbuttons (C04).

4.2 Verify that reactor power is decreasing. (C04).

4.3 Verify that all full length CEA groups are fully inserted (C04).

4.4 Ensure the turbine has tripped by depressing the turbine trip button (1) on the EHC insert panel (C07). Verify that all steam admission valves indicate closed (C07) and that generator megawatts indicate zero or negative (C07).

4.5 Ensure the generator ACB's are open 15G-8T-2 and 15G-9T-2 (C08). If not open, trip by using the emergency trip pushbuttons (C07). (Push both buttons simultaneously).

4.6 Verify the transfer of 6.9KV and 4.16VK buses to reserve station service transformer (RSST).

4.7 Verify feed water flow decreasing as the feedwater regulating valves are ramping down to the 5% open position (C05).

4.8 If the feed pumps are in manual speed control, ramp feed pump speed to minimum speed, and if two pumps are running, trip one pump.

4.9 Trip both heater drain pumps (if running).

4.10 Trip two condensate pumps if three were running. Trip one condensate pump if two were running.

5. SUBSEQUENT ACTIONS

5.1 Monitor Primary System Temperature.

5.1.1 Verify that steam dump and bypass valves are functioning to reach and maintain a no load TAVG of 532°F (C04-C05).

5.1.2 If the main steam isolation valves have closed or the main condenser is not available, use the atmospheric dump valves to maintain TAVG at 532°F (Corresponds to 900 PSIA secondary pressure). (C05).

5.2 Monitor pressurizer level decreasing to reach the no load programmed level of 40%. Switch to manual control if necessary. (C02/3).

5.3 Monitor Steam Generator Water Levels

5.3.1 Close the feedwater regulating valves and using the main steam generator feedpump and the 15% feedwater regulator bypass slowly return the steam generator water levels to normal (50-75%) (C05).

CAUTION: When steam generator water levels decrease below the feedwater spargers (≤45%) feedwater flow shall be limited to less than 600 gpm. If feedwater flow is lost for greater than 15 minutes and these conditions exist feedwater flow shall not exceed 168 gpm.

5.3.2 If the main steam generator feed pumps are not available start the electric and/or steam driven auxiliary feedpumps and supply feedwater observing the limits discussed above.

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5.3.3 If using the auxiliary feed pumps to supply the steam generators, secure the normal hydrazine feed pumps, open valves 2MS-15A and 2MS-15B and then start the auxiliary chemical feed pumps.

CAUTION If all condensate pumps must be secured, remove steam from the turbine building prior to securing the pumps by closing both main steam isolation valves. Ensure steam dump to condenser is secured and atmospheric dump valves are being used to control TAVG and then break condenser vacuum.

5.4 Monitor Primary System Pressure.

5.4.1 Use manual control of pressurizer sprays and heaters if necessary to return primary system pressure to normal (2250 PSIA) (C02/3).

5.5 If pressurizer relief valves had lifted, monitor quench tank parameters and verify valves have reseated by observing temperature indicators on C03.

5.6 If steam generator safety valves had lifted, verify that they have reseated.

5.7 Ensure at least two (2) reactor coolant pumps (RCP's) running. (1A or 1B should be one of the running pumps for pressurizer spray purposes.

5.8 Record all relay actions on rear of C08, open 15G-2X1-4, (visually verify stabs open) reset the relays, and then reclose 15G-8T-2 and 15G-9T-2.

5.9 Secure secondary plant equipment not necessary in maintaining a hot shutdown condition.

5.10 Verify main turbine motor suction pump running and manually start lift pumps and turning gear motor to ensure safe coast down of main turbine generator (C07).

NOTE: Lift pumps and turning gear will auto start if Step 5.10 is omitted.

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5.11 Verify steam generator feed pump turbine auxiliary oil pump running. Feed pumps turbine turning gear will automatically engage at zero speed.

5.12 Determine cause of reactor trip and correct.

5.12.1 If cause of trip was low condenser vacuum, refer to Emergency Procedure 2507 "Loss of Condenser Vacuum".

5.12.2 If cause of trip was high containment pressure, refer to Emergency Procedure 2506 "Loss of Coolant Incident" or 2509 "Steam Line Rupture".

5.12.3 If cause of trip cannot be corrected without plant cooldown, initiate plant operating procedure 2205 "Plant Shutdown".

5.13 Fill out Station Form SF-1001 (Plant Incident Report) and notify higher supervision in accordance with ACP 1.07.

5.14 As soon as conditions permit reset the turbine as follows:

5.14.1 Reset and close the reactor protective system switchgear breakers.

5.14.2 Reset the turbine and verify the intermediate stop valves (4) stroke to the full open position.

5.14.3 If the intermediate stop valves do not open, EHC pressure can be increased to provide additional force per the following:

5.14.3.1 Loosen the lock nut on the pressure compensator at the pump.

5.14.3.2 Note original EHC pressure.

NOTE: The pump discharge relief valves are set at approximately 2000 PSIG.

5.14.3.3 Turn the compensator clockwise until pressure equals 1900 PSIG.

5.14.3.4 After the valves open or if the extra pressure does not open the valves return the pressure to its original value.

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5.14.4 After the intermediate stop valves open the turbine may be tripped.

5.15 Notify Chemistry to perform an isotopic analysis for Iodine within a 2 to 6 hour period from the time of the trip if reactor power was greater than 15% at the time of the trip.

5.16 Monitor wide range power instrumentation. If the count rate for any channel decreases below .5 CPS and the channel is required to meet Technical Specification minimum channel requirements, reconnect the B-10 detector by depressing the B-10 off pushbutton.

5.17 If condenser vacuum is being maintained, monitor turbine steam seal header pressure and adjust as necessary to maintain 4 PSIG on the header.

5.18 Monitor system voltage and if necessary, request CONVEX to adjust system voltage to ensure adequate in house voltage.

Steam Supply System Rupture

DISCUSSION:

A rupture in the main steam system reduces the steam generator pressure and level, rapidly increases steam flow rate and causes cool down of the reactor coolant. The rate of steam release will decrease during the accident as steam pressure falls. With a negative moderator coefficient of reactivity, the cool-down will produce a positive reactivity addition which will increase core power. Depending on the initial conditions, break size and break location the reactor will be tripped by any of the following Plant Protective System signals: Low Steam Generator Pressure Low Steam Generator Level, High Linear Power Level, High Local Power Density or Low DNBR.

The decrease in main steam pressure will also initiate a main steam isolation signal (MSIS) which will close both main steam header stop valves, close both feed water header stop valves, secureboth main feedwater pumps and secure all four condensate pumps. The emergency feed system (EFS) is provided to supply water to the intact steam generator to remove reactor decay heat and maintain reactor coolant system (RCS) cool down capability following a main steam line rupture. The following engineering safety features (ESF) signals will be actuated by low pressurizer pressure or high containment pressure: containment cooling actuation signal (CCAS), safety injection actuation signal (SIAS). If the rupture is inside the containment the increased containment pressure could initiate a containment isolation actuation signal (CIAS) and a containment spray actuation signal (CSAS).

1.0 SYMPTONS

1.1 Rapid decrease in steam generator pressure and generated MW.

1.2 Increasing steam flow and feed flow.

1.3 Decrease in steam generator water level.

1.4 Rapid decrease in RCS temperature

1.5 Rapid decrease in RCS pressure.

1.6 Decrease in pressurizer level

1.7 Increasing reactor power

1.8 Loud noise and poor in plant visibility depending on location of rupture.

1.9 Increase in containment pressure, temperature, humidity and sump level if the rupture is inside containment.

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2.0 IMMEDIATE ACTIONS:

2.1 Immediate Automatic Actions

2.1.1 Reactor trip

2.1.2 Turbine trip

2.1.3 MSIS actuates

2.1.4 EFS actuates

2.1.5 SIS actuates at a pressurizer pressure of 1600 psig or a containment pressure of 5 psig.

2.1.6 CCS actuates at a pressurizer pressure of 1600 psig or a containment pressure of 5 psig.

2.1.7 CIS actuates at a containment pressure of 5 psig.

2.2 Immediate Operator Actions

2.2.1 Verify that the applicable immediate automatic actions in section 2.1 actuate. Trip the reactor and turbine if not already tripped and carry out reactor trip procedure (OP 2202.04)

2.2.2 Notify plant personnel of the casualty

2.2.3 Borate the reactor to shutdown boron concentration in accordance with OP 2202.48 - Emergency Boration.

2.2.4 Instrumentation indications will specify the location of the rupture. If steam generator pressure continues to decrease after the main steam stops have closed, the rupture is upstream of the main steam stop on the side with the steam generator with the decreasing pressure. For this inisolable case:

(1) Verify the main steam stops closed and feedwater flow secured to the affected steam generator.

(2) Secure the reactor coolant pumps in the affected loop.

(3) Insure that the affected steam generator's blowdown valves and atmospheric dump valve are closed.

(4) Carry out the appropriate follow- up action (section 3)

2.2.5 If instrumentation indicates that the rupture is downstream of the main steam stops, ie. steam generator pressure stabilized after the main steam stops closed.

(1) Verify the main steam stops closed and feedwater secured to the affected steam generator.

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(2) Insure that the affected steam generator's blowdown, atmospheric dump, and turbine bypass valves are closed.

(3) Carry out the appropriate follow-up actions (section 3).

3.0 Follow-up Actions:

3.1 Open the atmospheric steam dump isolation (s) on the unaffected steam generator (s) and bleed steam to control temperatures as necessary.

3.2 Restore and maintain steam generator level and pressure in the unaffected steam generator.

3.3 Restore and maintain pressurizer level in the normal operating band.

3.4 If CIS initiates, secure all reactor coolant pumps.

3.5 Check that the appropriate actions, initiated by the MSIS, EFAS, CCAS, and the CIAS have occured, if applicable.

3.5.1	MSIS	Appendix A
3.5.2	EFAS	Appendix B
3.5.3	CCAS	Appendix C
3.5.4	CIAS	Appendix D

3.6 Continue plant cool down and place the plant in a cold shutdown condition per OP 2102.10 - Plant Shutdown and Cool down, utilizing the unaffected steam generator (s).

3.7 When pressurizer level is restored to the normal operating band and containment pressure is below 5 psig, if the break was inside containment, block the pressurizer low pressure signal by reseting the low pressure trip for 400 PSI below pressurizer pressure. Reset SIS, CCS and CIS and restore charging and letdown flow to normal.

3.8 Sample the RCS for indication of fuel failure.

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MAIN STEAM ISOLATION SYSTEM
APPENDIX A

COMPONENT NUMBER	COMPONENT NAME	ACCIDENT POSITION
2P4A 2P4B, 2P4C 2P4D	Service Water Pumps	ON
2CV-1425-1 2CV-1427-2	Service Water to Aux. Cooling System	CLOSED
2CV-1530-1 2CV-1531-2 2CV-1542-2 2CV-1543-1	Service Water to/from Component Cooling Water Heat Exchanger	CLOSED
2CV-1525-1 2CV-1526-2	Service Water to Fuel Pool Heat Exchanger	CLOSED
2VEF25A 2VEF25B	Intake Structure Exhaust Fan	ON
2CV-1024-1 2CV-1074-1	Main Feed Isolation Valves	CLOSED
2CV-1010-1 2CV 1060-2	Main Steam Isolation Valves	CLOSED
2CV-1541-1 2CV-1560-2	Service Water Discharge to Emergency Cooling Pond	OPEN
2CV-1510-2 2CV-1511-1	Service Water Inlet to Containment Cooling Coils	OPEN
2CV-1513-2 2CV-1519-1	Service Water Outlet to Containment Cooling Coils	OPEN
2P1A 2P1B	Main Feedwater Pumps	OFF
2P2A,B,C,D	Condensate Pumps	OFF
2K2A, 2K2B	Main Turbines	TRIPPED

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EMERGENCY FEEDWATER ACTUATION SYSTEM
APPENDIX B

COMPONENT NUMBER	COMPONENT NAME	ACCIDENT POSITION
2P4A, 2P4B 2P4C, 2P4D	Service Water Pumps	ON
2P7B	Emergency Feedwater Pump	ON
2CV-0714-1	Flush Line Isolation Valve	CLOSED
2CV-0789-1	Flush Line Isolation Valve	CLOSED
2CV-0716-1 2CV-0711-2	Service Water Supply to Emergency Feedwater Pumps Permissive	OPEN
2CV-0789-1 2CV-0795-2	Condensate Supply to Emergency Feedwater Pumps	CLOSED
2CV 0340 2CV 0341 2SV 0317	Steam Supply to EFW Pumps	OPEN
2CV 1037-2 2CV 1037-1 2CV 1038-2 2CV 1039-1	EFW Pump Discharge Isolation Valves	OPEN
2CV 1025-1 2CV 1075-1 2CV 1026-2 2CV 1076-2	EFW Pump Discharge Valves	OPEN to the Intact Steam Generator

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CONTAINMENT COOLING ACTUATION SYSTEM
APPENDIX C

COMPONENT NUMBER	COMPONENT NAME	ACCIDENT POSITION
2VSF-1A, 2VSF-1B 2VSF-1C, 2VSF-1D	Containment Cooler Fans and Dampers (Interlocked)	ON
2UCD-8203-1 2UCD-8209-1 2UCD-8216-2 2UCD-8222-2	Bypass Dampers	OPEN
2CV-1511-1 2CV-1510-2	Service Water to Containment Cooling Coil	OPEN
2CV-1519-1 2CV-1513-2	Service Water From Containment Cooling Coil	OPEN

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CONTAINMENT ISOLATION ACTUATION SYSTEM
APPENDIX D

COMPONENT NUMBER	COMPONENT NAME	ACCIDENT POSITION
2CV-1066 2CV-1016	Steam Generator Blowdown Valves	CLOSED
2CV-2401 2CV-2400	Containment Vent Header Isolation Valves	CLOSED
2CV-2060 2CV-2061	Containment Sump Drain Isolation Valves	CLOSED
2CV-2202 2CV-2201	Reactor Drain Tank Isolation Valves	CLOSED
2CV-2850-2 2CV-3851-1 2CV-3852-2	Chill Water to/from Containment Coolers	CLOSED
2CV-5254-2 2CV-5255-1	Component Cooling Water from RCP's	CLOSED
2CV-5236-1	Component Cooling Water to RCP's	CLOSED
2SV-5800 2SV-5803	Reactor Drain Tank Sample	CLOSED
2SV-5802 2SV-5804	Quench Tank Gas Space Sample	CLOSED
2SV-5878 2SV-5871	Quench Tank Outlet Sample	CLOSED
2SV-5833 2SV-5843	Reactor Coolant Sample	CLOSED
2CV-8233 2CV-8231 2CV-8273 2CV-8271 2CV-8259 2CV-8261 2CV-8265 2CV-8263	H_2 Purge System Valves	CLOSED
2CV-8289-1 2CV-8284-2 2CV-8286-2 2CV-8291-1 2CV-8283-1 2CV-8285-1	Containment Purge Isolation Valves	CLOSED
2CV-4690-2	Denumeralized Water Supply Isolation Valve	CLOSED

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CONTAINMENT ISOLATION ACTUATION SYSTEM
APPENDIX D

COMPONENT NUMBER	COMPONENT NAME	ACCIDENT POSITION
2CV-4846	RCP Seal Bleed-off Isolation Valve	CLOSED
2CV-4821	Letdown Line Isolation Valve	CLOSED
2SV-8851 2SV-8852 2SV-8853 2SV-8854 2SV-8863 2SV-8864 2SV-8865 2SV-8866	Ventilation Isolation Valve Penetration Rooms	CLOSED
2VEF-38A 2VEF-38B	Penetration Room Purge Fans	ON
2SV-5876	SI Tank Sample	CLOSED
2CV-5852 2CV-5859	Steam Generator Sample Isolation	CLOSED

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EMERGENCY PROCEDURE NO. 2509

STEAM LINE RUPTURE

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1	2	6-29-76
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5	2	6-29-76
6	2	6-29-76
7	2	6-29-76

1.0 OBJECTIVE

To provide a procedure which will limit the expected rapid cooldown of the reactor coolant system (RCS) when steam flow is excessive due to a steam line rupture or rupture of a feedwater line downstream of the air assisted check valve.

2.0 DISCUSSION

Excessive steam flow from the steam generators (S/G) results in a cooldown of the RCS. This adds positive reactivity to the reactor (due to the negative moderator temperature coefficient) which results in a decrease in shutdown margin. The main steam isolation valves (MSIV) minimize the consequences of excess steam flow for breaks either upstream or downstream of the MSIV's.

If a steam line rupture occurs upstream of the MSIV's, the reverse flow check valve feature of the MSIV's will prevent a reverse flow of steam from the unaffected S/G. When pressure in the affected S/G decreases to 500 psia, the following will occur.

a. Both MSIV's will trip closed. & Bypass valves
b. Both feedwater control valves close.
c. Both air assisted feedwater check valves trip closed.
d. Both feedwater pumps trip.
e. A reactor trip signal is generated by the reactor protection system (RPS).

The S/G that has suffered the rupture will boil dry, stopping all heat transfer in that loop and therefore terminating the cooldown of the RCS.

The unaffected S/G and auxiliary feedwater system are utilized to bring the unit to a cold shutdown condition using OP 2206 (Plant Shutdown) and OP 2207 (Plant Cooldown) as guidelines.

If a feedwater line rupture occurs downstream of the air assisted check valve, steam will flow out of the break and the end result will be very similar to steam line break upstream of the MSIV's. The resultant cooldown of the RCS will be less severe for the following reasons:

a. Feedwater lines are smaller than main steam lines (18 inches versus 34 inches).

b. Steam must enter the broken feedwater line through small holes in the feedwater sparger.

If a steam line rupture occurs downstream of the MSIV's, both MSIV's will close when the pressure in either S/G falls to 500 psia. Excessive cooldown of the RCS is terminated and both S/G are unaffected and available for plant cooldown.

Due to the similarity of symptoms for a loss-of-coolant incident (LOCI) and a steam line rupture, it is difficult to differentiate between the two events. There are certain parameters which can be used to accurately distinguish which of the following has occurred:

a. Loss-of-coolant incident (LOCI).

b. Steam line rupture downstream of the MSIV's

c. Steam line rupture upstream of the MSIV's/feedwater line rupture downstream of air assisted check valve and outside the containment.

d. Steam line rupture/feedwater line rupture inside the containment.

The block diagram on Figure 2509-1 provides the operator with a means of establishing which emergency is occurring. In order to accomplish this identification, the first three steps of this procedure and Emergency Procedure 2505, Loss-of-Coolant Incident (LOCI), are identical.

Note: Small steam line breaks that do not result in closure of the MSIV's or reactor trip are not considered an emergency.

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3.0 SYMPTOMS

3.1 Major Symptoms

3.1.1 Major symptoms of steam line rupture upstream of MSIV's/feedwater line rupture downstream of air assisted check valve.

3.1.1.1 Pressure in one S/G will decrease rapidly while pressure in the other S/G will be erratic until stabilizing at the pressure corresponding to the new Tavg.

3.1.1.2 MSIV's will trip closed when the pressure decreases to 500 psia in the affected S/G (C05).

3.1.1.3 Pressure in the affected S/G will continue to decrease, while the pressure in the unaffected S/G will decrease to the saturation pressure corresponding to the existing Tavg resulting from the cooldown.

3.1.1.4 If rupture is inside containment, containment temperature and pressure will rapidly increase.

3.1.2 Major symptoms of steam line rupture downstream of MSIV's.

3.1.2.1 Pressure will decrease rapidly in both S/G's (C05).

3.1.2.2 MSIV will trip closed when the pressure decreases to 500 psia in either S/G (C05).

3.1.2.3 Pressure in both S/G's will stabilize and slowly return to the saturation pressure corresponding to the existing Tavg, approximately 532°F, which is being controlled by the atmospheric dump valves.

3.2 Other

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3.2.1 Reactor trip from low steam generator pressure, high reactor power and/or thermal margin/low pressure.

3.2.2 Rapidly decreasing pressurizer level and pressure (C05).

3.2.3 Mismatch between steam flow/feedwater flow (C05).

3.2.4 SIAS initiation (C01).

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3.2.5 Containment Isolation (C05).

3.2.6 High noise level.

4.0 IMMEDIATE ACTION

4.1 Carry out Emergency Procedure 2502 (Emergency Shutdown).

4.2 Verify auto closure or manually close the main steam isolation valves (MSIV's) (C05).

4.3 Refer to Figure 2500-1 to identify the emergency. If loss-of-coolant incident, refer to Emergency Procedure 2506 (Loss-of-Coolant Incident).

4.4 If the ruptured line is a steam line upstream of the MSIV's or a feedwater line downstream of the air assisted check valve, trip both reactor coolant pumps in the affected steam generator loop.

4.5 If the ruptured line is a steam line downstream of the MSIV's, maintain all four reactor coolant pumps running so both steam generators can be used as a heat sink. If Tavg decreases to a value $\leq 500^{\circ}F$, one RCP must be tripped.

5.0 SUBSEQUENT ACTIONS

5.1 As pressurizer pressure decreases, verify SIAS initiates and the following if applicable:

a. High pressure safety injection (HPSI) flow starts at approximately 1100 psig (C01).

b. Low pressure safety injection (LPSI) flow starts at approximately 200 psig (C01).

5.2 If no SIAS and Tavg less than $515^{\circ}F$, start emergency boration per OP 2514 (Emergency Boration). Emergency borate until Tavg stops decreasing or until the Cold S/D concentration is reached (RE Form 2208-12).

5.3 Verify actuation of containment spray if containment pressure reaches 27 psig (C01X).

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CAUTION: In no case should water be fed to the affected S/G. This is particularly important in the case where a detected break is *inside* the containment.

5.4 Start the auxiliary feed pumps (lined up to the unaffected S/G(s) and maintain water level. Refer to OP 2322 (Auxiliary Feedwater System).

5.5 Initiate maximum S/G blowdown on *affected* S/G (C05).

5.6 Commence orderly shutdown to cold shutdown conditions using OP 2205 (Plant Shutdown) and OP 2207 (Plant Cooldown) as guidelines.

5.7 Conduct plant survey to determine extent of damage.

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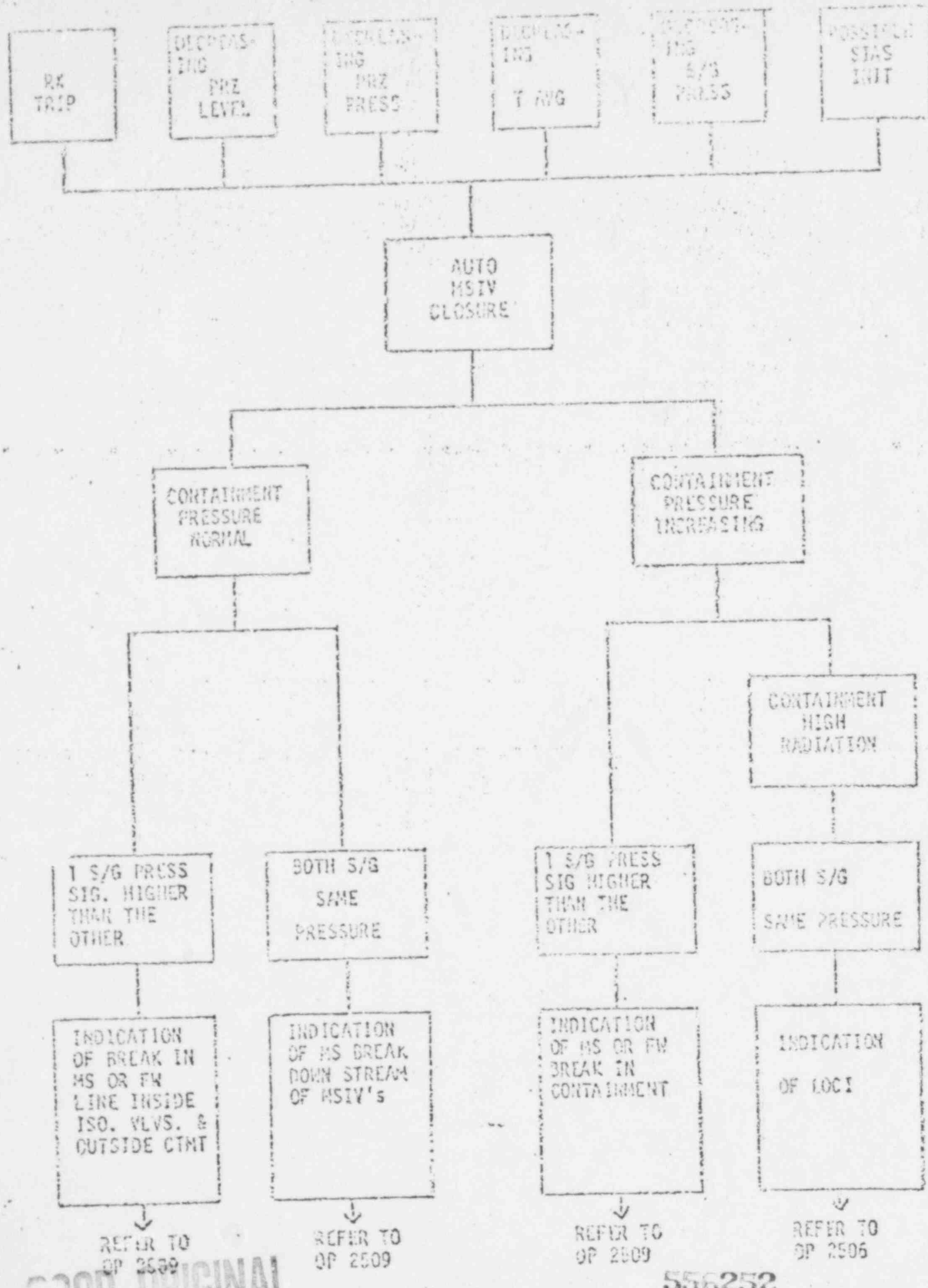

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FIGURE 2509-1

Uncontrolled Heat Extraction

A. PURPOSE

To describe the procedure to be taken in the event of an Uncontrolled Heat Extraction. If the cause of the uncontrolled heat extraction is a rupture downstream of the mainsteam isolation valves with a simultaneous complete loss of OFF-SITE AC power, follow EP-29.

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B. SYMPTOMS

1. Any one or more of the following alarms may be present:

   a. Pressurizer lever Lo

   b. Pressurizer lever Lo-Lo

   c. Pressurizer pressure Lo

   d. Pressurizer safety injection signal Lo-Lo pressure

   e. TM/Low Pressure channel trip

   f. Low pressure SG-2A channel trip

   g. Low pressure SG-2B channel trip

   h. SGLS circuit "A" actuated

   i. SGLS circuit "B" actuated

   j. Reactor trip

   k. Safety injection actuation channel A

   l. Safety injection actuation channel B

2. Any one or more of the following indications may be present:

   a. Rapid reduction in steam generator pressure.

   b. Increasing containment pressure

   c. Reduction in RCS temperature causing a corresponding decrease in pressurizer level and pressure.

   d. Steam generator level oscillations

   e. Steam flow-feed flow mismatch

   f. Change in generator electrical output

   g. Noise if a steam line/feed line rupture occurs outside containment.

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C. IMMEDIATE ACTION

1. Depress the manual reactor trip pushbutton. Insure that all regulating and shutdown CEA's have been fully inserted and that reactor power is decreasing.

2. Insure turbine has tripped and all stop and intercept valves closed.

3. Insure generator breakers 4 and 5 have tripped and that the generator field breaker has opened.

4. Shut the MSIV's (Main Steam Isolation Valves).

5. Secure the main feedwater pumps.

6. Ensure all available charging pumps are operating.

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D. FOLLOW-UP ACTION

1. If the Engineered Safety Features System was actuated by the transient perform/verify the following:

   a. Ensure safety injection flow is being delivered to the RCS by verifying high pressure safety injection flows.

      NOTE: Although the low pressure safety injection pumps will be running the RCS pressure probably will not drop to the point where low pressure injection will occur.

   b. Ensure containment spray flow exists if CPHS actuated the Engineered Safety Features System, (most likely due to steam line rupture in containment).

   c. Ensure emergency boration of the RCS is taking place.

   d. If Component Cooling Water pump discharge pressure is greater than 133 psig and the Component Cooling Water pump motor amps are less than 300 A, restore CCW flow to the RC pumps by placing HCV-438A/438B/438C/ and 438D control switches in the PULL TO OVER-RIDE position. If CCW flow can be restored to the RC pumps, maintain required pumps in operation.

      NOTE: An exception to this occurs if uncontrolled heat extraction occurs upstream of MSIV's. In this case the RC pumps supplying affected steam generator should be secured.

   e. Ensure CIAS closed main feedwater isolation valves HCV-1385 and HCV-1386.

   f. When normal water level has been restored in the pressurizer, throttle injection flow and/or secure charging pump(s)/high pressure safety pump(s) as required to prevent obtaining a water solid RCS.

      NOTE: An uncontrolled heat extraction causes a reduction in RCS temperature. It should be kept in mind that with the RCS temperature below normal operating temperatures (especially below the minimum temperature for full pressurization) an overpressurization is possible if high head pumps (HPSI and charging pumps) are allowed to completely refill the RCS to a water solid condition. The operator should ensure that injection flow is throttled or used intermittantly once normal water level is restored in the pressurizer.

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D. FOLLOW-UP ACTION (Continued)

g. When normal water level has been restored in the pressurizer and containment pressure has been verified to be less than 3 PSIG, reset the Engineered Safety Features System by resetting the following devices in the order indicated:

(1) PPLS block switch to the BLOCK position.

(2) 86-A/PPLS, 86-B/PPLS, 86-A/CPHS and 86-B/CPHS.

(3) 86-A/SIAS, 86-B/SIAS, 86-A/CSAS and 86-B/CSAS.

(4) 86-AX/SIAS and 86-BX/SIAS.

(5) 86-A/CIAS and 86-B/CIAS.

(6) 86-A/VIAS and 86-B/VIAS.

(7) 86-A/SPARE and 86-B/SPARE.

(8) 86-1/SI-1, 86-2/SI-1, 86-1/SI-2, 86-2/SI-2, 86-1/S2-1, 86-2/S2-1, 86-1/S2-2, and 86-2/S2-2.

(9) 86-A/D1 and 86-B/D2.

(10) 86-B/D1 and 86-A/D2.

(11) 86A-OR/1AD1, 86B-OR/1AD1, 86A-OR/1AD2 and 86B-OR/1AD2.

h. Other safeguards equipment may now be secured as requested by the Shift Supervisor.

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D. FOLLOW-UP ACTION (Continued)

2. IF closure of the MSIV's did not terminate the transient, perform the following:

   a. Determine which steam generator is the affected steam generator.

      NOTE: The affected steam generator will experience a more rapid pressure reduction than the unaffected steam generator. The unaffected steam generator pressure will be the saturation pressure for the existing RCS temperature. Also the RCS cold leg temperatures on the affected loop will drop more rapidly than those on the unaffected loop.

   b. Secure RC pumps in the affected loop.

   c. Ensure that NO feedwater (either main or auxiliary) is admitted to the affected steam generator.

   d. Feed the unaffected steam generator with an auxiliary FW pump via the emergency feedwater nozzles as required to restore/maintain level at 80% or greater.

   e. Cooldown the RCS to below 300°F per OP-6 after verifying at least cold shutdown boron concentration exists in the reactor coolant system.

   f. Decay heat and RC pump heat may be removed by performing any one or more of the following:

      (1) Operation of the steam driven auxiliary feedwater pump (FW-10) with steam being supplied from unaffected steam generator.

          NOTE: If A steam generator has the rupture, ensure YCV-1045A is closed and open YCV-1045B. If B steam generator has the rupture, ensure YCV-1045B is closed and open YCV-1045A.

      (2) Periodic remote operation of steam generator safety valve on the unaffected steam generator.
          MS-291 for steam generator A
          MS-292 for steam generator B

      (3) Opening the main steam isolation valve bypass on the unaffected steam generator and operation of the atmospheric dump valve or steam bypass valve if condenser vacuum is satisfactory.

          NOTE: (On following page)

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D. FOLLOW-UP ACTION (Continued)

2. f. (3) (Continued)

NOTE: CPHS or SGLS closes the MISV's and MSIV bypasses. Either the accident signal must be reset or power removed from the MSIV bypass valve actuator before bypass valve operation is possible.

(4) Initiation of steam generator blowdown.

NOTE: CIAS secures blowdown. Only after accident relays are reset can blowdown be restored.

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D. FOLLOW-UP ACTION (Continued)

3. IF closure of the MSIV's terminated the transient, perform the following:

   a. Verify that the RCS boron concentration is at least that required for the cold shutdown condition. If not, emergency borate the system.

   b. Attempt to isolate the component which caused the uncontrolled heat extraction.

   c. If isolation is possible, decay heat and RC pump heat can be removed by opening the main steam isolation valve bypasses and operating the atmospheric dump valve as required.

   d. If isolation is not possible, decay heat and RC pump heat can be removed by any one or more of the following:

      (1) Operation of the steam driven auxiliary feedwater pump (FW-10).

      (2) Periodic remote operation of steam generator safety valves MS-291 and MS-292.

      (3) Steam generators blow-down (if CIAS reset).

      (4) Modulated opening of the main steam isolation valve bypasses which will blow steam through any rupture.

   e. Feed the steam generators with an auxiliary feedwater pump via the emergency feedwater nozzles as required to restore/maintain level at 80% or greater.

   f. Ensure that no more than 3 RC pumps are operating if RCS temperature is less than 500°F.

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D. FOLLOW-UP ACTION (Continued)

4. If radioactivity above normal background was present in the steam generator secondary sides prior to the transient initiate the Site Emergency Plan and ensure that the Control Room is tenable by:

   a. Checking all access doors closed.

   b. Ensure that the control room ventilation system is in the filtered air makeup mode by placing the mode switch on the ventilation panel in the filtered air makeup mode.

   c. Ensure a positive pressure exists in the Control Room (don respiratory protection if a positive pressure does not exist).

5. Follow applicable portions of EP-1.

6. At the earliest opportunity sample the steam generator secondary side for radioactivity levels to verify the integrity of the steam generator tubes.

E. DISCUSSION

The major objective for an uncontrolled heat extraction is to minimize the RCS cool-down and to ensure adequate reactor shutdown margin. To achieve this it is important to:

1. Ensure that the Main Steam Isolation Valves (MSIV's) are closed. This will terminate the transient if the uncontrolled heat extraction occurred downstream of the MSIV's. Closing the MSIV's ensures that only one steam generator can contribute to an uncontrolled heat extraction if the uncontrolled heat extraction is occurring upstream of the MSIV's.

2. Secure the main feedwater pumps. This will terminate an uncontrolled heat extraction transient due to excessive feedwater addition for example. Also, if an uncontrolled heat extraction occurs upstream of the main steam isolation valves, the affected steam generator will have to be boiled dry to terminate the transient. <u>If</u> feedwater flow <u>continues</u> to the affected steam generator the transient <u>will continue</u>.

3. Verify that the RCS boron concentration is such that at least the cold shutdown condition is assurred. Emergency boration by way of the CVCS can be utilized if required. Emergency boration is automatically actuated if the Engineered Safety Features System is actuated.

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EMERGENCY PROCEDURE
EP-29

Steam Line Rupture With a Complete Loss of Off-Site AC Power

A. PURPOSE

To describe the steps to be taken if a steam line rupture occurs downstream of the main steam isolation valves in conjunction with a loss of off-site power.

NOTE: If the offsite power low signal is received when a PPLS/SIAS signal is in, the 4160V buses will load shed and re-sequence loads on the diesels.

B. SYMPTOMS

1. Any or more of the following alarms may be present:

   a. Pressurizer level Lo

   b. Pressurizer level Lo-Lo

   c. Pressurizer pressure Lo

   d. Pressurizer safety injection signal Lo-Lo pressure

   e. TM/Low Pressure channel trip

   f. Low pressure SG-2A channel trip

   g. Low pressure SG-2B channel trip

   h. SGLS circuit "A" actuated

   i. SGLS circuit "B" actuated

   j. Reactor trip

   k. Safety injection actuation channel A

   l. Safety injection actuation channel B

   m. Low reactor coolant flow trip

   n. Low 4160V and 480 Bus voltage alarms

2. Any one or more of the following indications may be present:

   a. Rapid reduction in steam generator pressure

   b. Increasing containment pressure

   c. Reduction in RCS temperature causing a corresponding decrease in pressurizer level and pressure

   d. Steam generator level oscillations

   e. Steam flow-feed flow mismatch

   f. Change in generator electrical output

   g. Noise if a steam line/feed line rupture occurs outside containment

   h. Loss of AC lighting and energization of DC emergency lighting

C. IMMEDIATE ACTION

1. Depress the manual reactor trip pushbutton. Insure that all regulating and shutdown CEA's have been fully inserted and that reactor power is decreasing.

2. Insure turbine has tripped and all stop and intercept valves closed.

3. Insure generator breakers 4 and 5 have tripped and that the generator field breaker has opened.

4. Shut the MSIV's (Main Steam Isolation Valves).

5. Insure the following functions have occurred and initiate those that have not by manual initiation:

   a. Turbine generator emergency DC oil pump and emergency DC seal oil pump in operation.

   b. Normal and standby feeder breakers to 4160V busses are open.

   c. Load shedding on 4160V busses. This should occur within 2.5 seconds after trip. If not, manually shed busses 1A3 and/or 1A4 except for 480V feeder breakers.

   d. Within 10 seconds after trip, DG-1 and DG-2 should be at rated speed and voltage. Breaker 1AD1 and 1AD2 should have auto closed, energizing busses 1A3 and 1A4.

      NOTE: Operator has the option of manually closing the breakers for the HPSI, LPSI, CS or FW-6 pumps with the control switch and with an undervoltage condition on the bus(es). However, with LPSI and FW-6 breakers closed in on the bus and the busses associated diesel breaker open, the auto closure of the diesel breaker is locked out.

CAUTION: If the offsite power low signal is received when a PPLS/SIAS signal is in, the 4160V buses will load shed and re-sequence loads on the diesels.

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D. FOLLOW-UP ACTION

1. If the Engineered Safety Features System was actuated by the transient, perform/verify the following:

   a. Ensure safety injection flow is being delivered to the RCS by verifying high pressure safety injection flows.

      NOTE: Although the low pressure safety injection pumps will be running, the RCS pressure probably will not drop to the point where low pressure injection will occur.

   b. Ensure containment spray flow exists if CPHS actuated the Engineered Safety Features System (most likely due to steam line rupture in containment).

   c. Ensure emergency boration of the RCS is taking place.

   d. If Component Cooling Water pump discharge pressure is greater than 133 psig and the Component Cooling Water pump motor amps are less than 300 A, restore CCW flow to the RC pumps by placing HCV-438A/438B/438C and 438D control switches in the PULL TO OVER-RIDE position. If CCW flow can be restored to the RC pumps, maintain required pumps in operation.

      NOTE: An exception to this occurs if uncontrolled heat extraction occurs upstream of MSIV's. In this case the RC pumps supplying affected steam generator should be secured.

   e. Ensure CIAS closed main feedwater isolation valves HCV-1385 and HCV-1386.

   f. When normal water level has been restored in the pressurizer, throttle injection flow and/or secure charging pump(s)/high pressure safety pump(s) as required to prevent obtaining a water solid RCS.

      NOTE: An uncontrolled heat extraction causes a reduction in RCS temperature. It should be kept in mind that with the RCS temperature below normal operating temperatures (especially below the minimum temperature for full pressurization) an overpressurization is possible if high head pumps (HPSI and charging pumps) are allowed to completely refill the RCS to a water solid condition. The operator should ensure that injection flow is throttled or used intermittantly once normal water level is restored in the pressurizer.

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PRESSURIZER SYSTEMS FAILURES

SECTION I: LEAKING PRESSURIZER CODE SAFETY VALVE

1.0 SYMPTOMS

1.1 Code safety valve discharge temperature high (alarm at 135°F).

1.2 Pressurizer proportional heaters operating at 100%.

1.3 Excessive charging flow (charging flow greater than letdown flow to maintain constant Pressurizer level).

1.4 Quench Tank temperature, level, and/or pressure increasing.

2.0 IMMEDIATE ACTION

2.1 Determine Reactor Coolant System leak rate.

2.2 Determine leak rate to Quench Tank.

3.0 FOLLOW-UP ACTION

3.1 If total Reactor Coolant System leakage is in excess of that allowed by Technical Specifications, or earlier if required by plant supervision, begin a shutdown and cooldown per OP 2102.10 (Plant Shutdown and Cooldown) and repair leaking valve(s) prior to resuming operations.

3.2 Monitor Quench Tank pressure, level, and temperature; maintain Quench Tank parameters within the limits described in OP 2103.07 (Quench Tank Operation).

SECTION III: PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION

1.0 SYMPTOMS

1.1 Pressurizer Level Channel High/Low Deviation Alarm.

1.2 Pressurizer level deviating from setpoint during steady state conditions.

1.3 Abnormal charging and letdown flows.

1.4 One control level indication differs significantly from the other.

2.0 IMMEDIATE ACTION

2.1 If Pressurizer Level Control System failure has caused an unbalance between charging and letdown flow, take Manual control of the Letdown Throttle Valve and restore letdown flow to normal.

2.2 Operate backup charging pumps as required to maintain charging flow consistent with letdown flow.

2.3 Use the temperature compensated pressurizer level indicator (2LI-4625 on 2C-04) for backup level indication if one of the control channel level indicators is inoperable.

3.0 FOLLOW-UP ACTION

3.1 If the failure was in the controlling level channel, place channel selector switch 2HS-4628 on 2C-04 to the opposite channel and restore the Letdown Throttle Valve to Automatic control.

3.2 If a level control channel has failed low, place the channel defeat switch, 2HS-4642 on 2C-04, to the unaffected channel to regain normal control of the pressurizer heaters.

3.3 Tag affected component as inoperable.

3.4 Initiate action to have faulty component repaired and/or calibrated.

SECTION VII: LOSS OF ALL PRESSURIZER LEVEL INDICATION

1.0 SYMPTOMS

1.1 Loss of all Pressurizer level indication.

NOTE

This procedure assumes that Pressurizer level was in its normal range.

2.0 IMMEDIATE ACTIONS

2.1 Take Manual control of the Letdown Flow Control Valve and adjust flow as necessary.

2.2 Place the control switch for the VCT inlet valve to the "VCT" position to prevent any loss of water to the Waste Processing System.

2.3 If both level indications fail low, manually operate backup heaters to control pressure.

3.0 FOLLOW-UP ACTIONS

3.1 Slowly reduce Turbine load while maintaining T_{AVG} equal to T_{REF}.

3.2 Adjust the Letdown Flow Control Valve as necessary to maintain a makeup rate of approximately 75 gallons for every 1°F decrease in T_{AVG}.

3.3 Initiate makeup flow to the VCT as necessary and record the total number gallons of makeup added.

NOTE

The rate of Turbine load reduction will depend on the rate mak up water can be added to the system. Use additional charging pumps if it is desirable to increase the rate of load reduction.

3.4 Place the plant in the Hot Standby condition.

NOTE

Approximately 2900 gallons of makeup water must be added to the Reactor Coolant System to maintain a constant Pressurizer level while decreasing T_{AVG} from 583°F to 544.6°F.

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4/14/79

To: Denny Ross

From: Sam Bryan, IE

16 pages

Bulletin 79-06A 1 cy
79-06B 1 cy

POOR ORIGINAL

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(Draft letterto all B&W, CE, and GE power reactor facilities with an operating license and all power reactor facilities with a construction permit and Ft. St. Vrain.)

IE Bulletin No. 79-06A

Addressee:

The enclosed Bulletin No. 79-06A, is forwarded to you for information. No written response is required. If you desire additional information regarding this matter, please contact this office.

Sincerely,

Signature
(Regional Director)

Enclosure:
IE Bulletin No. 79-06A

556271

(Draft letterto all B&W, Westinghouse, and General Electric, power reactor facilities with an operating license and all power reactor facilities with a construction permit and Ft. St. Vrain.)

IE Bulletin No. 79-06B

Addressee:

The enclosed Bulletin No. 79-06B, is forwarded to you for information. No written response is required. If you desire additional information regarding this matter, please contact this office.

Sincerely,

Signature
(Regional Director)

Enclosure:
IE Bulletin No. 79-06B

556273

1, 10

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

APRIL 12 1979

MEMORANDUM FOR: E. G. Case, Deputy Director
Office of Nuclear Reactor Regulation

FROM: D. F. Ross, Deputy Director
Division of Project Management

SUBJECT: SUMMARY OF MEETING WITH COMBUSTION ENGINEERING (CE)-
CORRECTIVE ACTIONS FOR COMBUSTION ENGINEERING NSSS
PLANTS AS A RESULT OF THREE MILE ISLAND UNIT 2
INCIDENT

On April 11 and 12, 1979, the NRC staff met with respresentatives of Combustion Engineering, Incorporated (CE) in Bethesda, Maryland, to discuss short term corrective actions to be implemented at CE pressurized water reactors (PWR) as a result of the incident at Three Mile Island Unit 2. Several CE PWR licensees were in attendance. A list of attendees is attached (Enclosure 1).

April 11, 1979 Meeting

The meeting opened with an overview of the events at Three Mile Island Unit 2 (TMI-2) which require immediate attention by all operating PWRs as these events are perceived by the staff in light of information available at this time. These events are identified as Items 1 thru 12 in the NRC Office of Inspection and Enforcement (OI&E) Bulletin 79-05A of April 5, 1979 (Enclosure 2). The staff specifically noted that the responsibility for development of corrective actions for these items rests with CE and the utilities. The corrective actions that are needed are specific instructions to be issued immediately to licensees of CE PWRs. These corrective measures will be reviewed by the NRC staff and issued by means of an OI&E Bulletin. D. Ross of the NRC staff read through the items in the B&W bulletin (Enclosure 2) and asked for comments and agreement that the items were suitable for CE designed plants.

Items 1 through 3 were agreed to by CE (agreement meaning that the item was appropriate for a CE designed plant).

Item 4 consists of four parts. They concern the overriding of automatic actions of engineered safety features (ESF).

CE was unwilling to speak on this item because they considered this a prerogative of their customers. They stated that they provide guidelines for the development of procedures by the utilities.

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CE stated that SI actuation occurs on the following signals (among others):

1. low primary pressurizer pressure

2. high containment pressure

Containment isolation is actuated by the high containment pressure (with the same set point as for SI actuation).

CE stated that while pressurizer level is the main parameter looked at in the guidelines, other system parameters are also used by some CE customers.

CE has not provided a guideline for turning off the safety injection to its customers.

CE agreed with item 4a (the operator should not override automatic actions of emergency safeguards features).

A representative of Baltimore Gas & Electric Company questioned the reason for a time requirement in item 4b concerning conditions under which the HPI could be turned off. He questioned why a pressure indication was not sufficient. The point was that if the Reactor Coolant System (RCS) were to approach going solid, pressure (subcooling) indication would be sufficient, regardless of the time that the HPI had been in operation. The staff noted his comment.

The question of the HPI causing reactor vessel pressure in excess of the allowable limits was discussed. CE stated that they had performed some fracture mechanics calculations of this type for the steam line break for vessels of different ages and these showed acceptable results. The analyses were previously reported to the staff in the letters listed below.

1. June 4, 1975 letter from W. Corcoran, CE to R. Maccary, NRC.

2. June 24, 1975 letter from W. Corcoran, CE to F. Schroeder, NRC.

CE stated that reactors designed by them have not experienced a stuck open relief valve. For this event, the pressurizer level could increase, although the primary system would be depressurizing.

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CE related a case in which the system drained down to a pressurizer level of 1% due to a drain valve that was inadvertently left open during a test (pre-nuclear). There was no flashing or change of direction in pressurizer level. However, this event was not directly applicable to the discussion since the drain was releasing water inventory from the water space rather than steam space.

CE stated that the analysis of the inadvertent opening of a relief valve showed that the two phase level reached the top of the pressurizer with a void fraction in the pressurizer of approxiamtely 25%.

CE stated that under this condition they would expect the pressurizer level instrumentation to give a true indication of level.

The staff asked whether the operator had to take any action based on level. CE responded that he did not and furthermore, that level did not enter into any safety system actions.

The staff then asked CE if the pressurizer could be full while the core was empty. CE replied that the analysis of the inadvertent opening of a relief valve showed that the pressurizer would drain. The staff questioned whether the computer code used for the analysis would have predicted this phenomenon. CE stated that the code was an evaluation model code. The staff will pursue this further with CE.

This completed the discussion of Item 4.

Item 5 concerned verifying that the auxiliary feedwater (AFW) valves are in the proper position. CE agreed with this item and stated further that the AFW systems on all CE operating plants are manually actuated. Analyses of all transients in the FSAR showed that with a delay of 10 minutes before initiating AFW flow, the pressurizer relief valves would not open.

CE agreed that items 6 through 10 of the OI&E Bulletin were appropriate.

CE had stated earlier that they had not come prepared to answer these items in detail. They stated that the answers they gave could be considered those of the Corporation however.

The staff held a caucus and decided that more information was required in order to write the bulletin , and CE was given an additional 24 hours to make comments in the following areas:

1. ESF reset criteria

2. What criteria are now used for turning off HPI? What temperature and pressure criteria are used?

3. Should NRC advise utilities on CVCS operation?

4. Further discussion of fracture mechanics.

5. Criteria for tripping the reactor coolant pump.

6. List operator actions based on pressurizer level.

7. Provide a CEFLASH calculation for a small break on the pressurizer fluid dynamics.

It was decided to continue the meeting on April 12, 1979, at 1:30 pm.

<u>April 12, 1979 Meeting</u>

The meeting opened with a review of the NRC intentions to issue bulletins to Westinghouse Electric Corporation and Combustion Engineering reactor licensees by tomorrow, April 13, 1979. It was noted that Bulletin 79-06 was issued on April 11, 1979, and contained general guidance for all PWR reactor licensees (except Babcock & Wilcox plant licensees). The bulletins to be issued tomorrow will be based on but provide more specific guidance than Bulletin 79-06.

The meeting then proceeded to the seven point agenda identified at the end of the previous day's meeting. These seven points correspond to the provisions of item 4 of IE Bulletin 79-05A.

The CE representatives discussed these provisions as follows:

4.a. (agenda item 1) CE agreed that this was appropriate for their facilities and suggested additional clarifying instructions to the plant operator. The staff will consider this suggestion.

4.b. (1) and (2) (agenda items 2, 3 and 4) CE stated that they have been investigating these provisions since the TMI-2 incident, and they confirmed the information given to us in the April 11 meeting regarding fracture mechanics. Based on their investigations and the referenced information (identified in the April 11, 1979 minutes), they agreed that the provisions of item 4 were appropriate for their facilities.

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4.c. (agenda item 5) The CE representatives believe that additional clarification should be added to this provision such that not all reactor coolant pumps should be run, but at least one pump per cooling loop should be run. It was recognized that, for some facilities, the proviso that one pump per loop be run would require all reactor coolant pumps to be run. The staff will consider this addition.

4.d. (agenda item 6 & 7) CE agrees with this provision as it is presently worded. Regarding their emergency core cooling code (CE FLASH) calculation for a small pressurizer break, CE representatives state that some information is available on the CE System 80 docket (Safety Analysis Report Chapter 6). This information provides pressurizer pressure as a function of time. CE will, after a check of proprietary considerations, make available information regarding pressurizer level as a function of time for this small pressurizer steam space break (equivalent to a 4" dia. hole).

Based on the information presented by CE, the staff intends to proceed with issuance of a bulletin with short term corrective actions to CE facility licensees.

Denwood Ross

Denwood F. Ross, Deputy Director
Division of Project Management

Enclosures:
As stated

cc w/encl:
See next page

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R. W. Reid
V. Noonan
G. Knighton
M. Fletcher
D. Brinkman
Attorney, OELD
R. Fraley, ACRS(16)
J. R. Buchanan
TERA
NRC Participants

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Enclosure 1

LIST OF ATTENDEES

COMBUSTION ENGINEERING MEETING 04/11/79

NRC

M. Fletcher, DOR
R. Lobel, DOR
F. Orr, DSS
A. Ignatonis, DSS
F. Combs, OCA
S. Droggitis, OCA
G. Sauter, OCM
J. L. Crews, I&E Region V
N. C. Moseley, I&E
S. Diab, DOR
D. Ross, DPM
E. G. Case, NRR
A. Thadani, DSS
D. Crutchfield, NRR
I. Villavla, DPM
D. B. Vassallo, DPM
R. S. Boyd, DPM
D. Skovholt, DPM
L. P. Crocker, DPM
F. Schroeder, DSS
S. H. Hanauer, DSS
L. B. Engle, DPM
S. Varga, DPM
D. C. DiIanni, DOR
A. J. Szukewicz, DSS
P. F. Collins, DPM
J. J. Holman, DPM
R. D. Silver, DOR
E. Mckenna
P. S. Kapo, DOR
M. Mendonca, DOR
C. Nelson, DOR
R. L. Denning, MPA
D. G. Eisenhut, DOR
T. A. Ippolito, DOR
R. P. Snaider, DOR
E. L. Conner, DOR
W. A. Paulson

Northeast Utilities

R. M. Kacick

Baltimore Gas & Electric

C. H. Cruse
P. C. L. Olson

Combustion Engineering

R. G. Walker
C. L. Kling
D. A. Kreps
J. Crawford
W. E. Burchill
C. B. Brinkman
R. S. Daleas
J. Longo

Consumers Power Company

D. J. VandeWalle
D. P. Hoffman

LP&L

J. Costello

Omaha Public Power District
(Pickard, Lowe & Garrick)

T. R. Robbins

NUS Corporation

G. C. Millman

Yankee Atomic Electric (Maine Yankee)

W. H. Reed

Babcock & Wilcox

R. Borsum

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Enclosure 1a

LIST OF ATTENDEES

COMBUSTION ENGINEERING/NRC MEETING 04/12/79

NRC

M. H. Fletcher, DOR
F. Orr, DSS
F. Combs, OCA
E. L. Conner, DOR
E. McKenna, DOR
S. Diab, DOR
J. F. Stolz, DPM
L. Engle, DPM
R. P. Snaider, DOR
R. K. Major, ACRS

Combustion Engineering

W. E. Burchill
J. D. Crawford
D. A. Kreps
C. B. Brinkman
J. V. Strimaitis
R. S. Bell
C. L. Kling
V. M. Callahan
F. L. Carpentino
D. Ayres
R. G. Walker

OPPD (PLG)

K. Woodard

Potomac Alliance

T. Challeley

Baltimore Gas & Electric

R. E. Denton
C. H. Cruse
R. M. Douglass
R. C. L. Olson

Bechtel

B. T. Ritter
P. Schwartz
G. J. Falibota

Northeast Utilities

P. L'Heureux

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, DC 20555

Enclosure 2

APRIL 5, 1979

IE Bulletin 79-05A

NUCLEAR INCIDENT AT THREE MILE ISLAND - SUPPLEMENT

Description of Circumstances:

Preliminary information received by the NRC since issuance of IE Bulletin 79-05 on April 1, 1979 has identified six potential human, design and mechanical failures which resulted in the core damage and radiation releases at the Three Mile Island Unit 2 nuclear plant. The information and actions in this supplement clarify and extend the original Bulletin and transmit a preliminary chronology of the TMI accident through the first 16 hours (Enclosure 1).

1. At the time of the initiating event, loss of feedwater, both of the auxiliary feedwater trains were valved out of service.

2. The pressurizer electromatic relief valve, which opened during the initial pressure surge, failed to close when the pressure decreased below the actuation level.

3. Following rapid depressurization of the pressurizer, the pressurizer level indication may have lead to erroneous inferences of high level in the reactor coolant system. The pressurizer level indication apparently led the operators to prematurely terminate high pressure injection flow, even though substantial voids existed in the reactor coolant system.

4. Because the containment does not isolate on high pressure injection (HPI) initiation, the highly radioactive water from the relief valve discharge was pumped out of the containment by the automatic initiation of a transfer pump. This water entered the radioactive waste treatment system in the auxiliary building where some of it overflowed to the floor. Outgassing from this water and discharge through the auxiliary building ventilation system and filters was the principal source of the offsite release of radioactive noble gases.

5. Subsequently, the high pressure injection system was intermittently operated attempting to control primary coolant inventory losses through the electromatic relief valve, apparently based on pressurizer level indication. Due to the presence of steam and/or noncondensible voids elsewhere in the reactor coolant system, this led to a further reduction in primary coolant inventory.

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6. Tripping of reactor coolant pumps during the course of the transient, to protect against pump damage due to pump vibration, led to fuel damage since voids in the reactor coolant system prevented natural circulation.

Actions To Be Taken by Licensees:

For all Babcock and Wilcox pressurized water reactor facilities with an operating license (the actions specified below replace those specified in IE Bulletin 79-05):

1. (This item clarifies and expands upon item 1. of IE Bulletin 79-05.)

   In addition to the review of circumstances described in Enclosure 1 of IE Bulletin 79-05, review the enclosed preliminary chronology of the TMI-2 3/28/79 accident. This review should be directed toward understanding the sequence of events to ensure against such an accident at your facility(ies)

2. (This item clarifies and expands upon item 2. of IE Bulletin 79-05.)

   Review any transients similar to the Davis Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item.

3. (This item clarifies item 3. of IE Bulletin 79-05.)

   Review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed.

4. (This item clarifies and expands upon item 4. of IE Bulletin 79-05.)

Review the actions directed by the operating procedures and training instructions to ensure that:

a. Operators do not override automatic actions of engineered safety features.

b. Operating procedures currently, or are revised to, specify that if the high pressure injection (HPI) system has been automatically actuated because of low pressure condition, it must remain in operation until either:

(1) Both low pressure injection (LPI) pumps are in operation and flowing at a rate in excess of 1000 gpm each and the situation has been stable for 20 minutes, or

3 (2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing RCS pressure. If 50 degree subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated.

2 c. Operating procedures currently, or are revised to, specify that in the event of HPI initiation, with reactor coolant pumps (RCP) operating, at least one RCP per loop shall remain operating.

4 d. Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water inventory in the reactor primary system.

5. (This item revises item 5. of IE Bulletin 79-05.)

Verify that emergency feedwater valves are in the open position in accordance with item 8 below. Also, review all safety-related valve positions and positioning requirements to assure that valves are positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance and testing, to ensure that such valves are returned to their correct positions following necessary manipulations.

6. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to cause containment isolation of all lines whose isolation does not degrade core cooling capability upon automatic initiation of safety injection.

7. For manual valves or manually-operated motor-driven valves which could defeat or compromise the flow of auxiliary feedwater to the steam generators, prepare and implement procedures which:

   a. require that such valves be locked in their correct position; or

   b. require other similar positive position controls.

8. Prepare and implement immediately procedures which assure that two independent steam generator auxiliary feedwater flow paths, each with 100% flow capacity, are operable at any time when heat removal from the primary system is through the steam generators. When two independent 100% capacity flow paths are not available, the capacity shall be restored within 72 hours or the plant shall be placed in a cooling mode which does not rely on steam generators for cooling within the next 12 hours.

   When at least one 100% capacity flow path is not available, the reactor shall be made subcritical within one hour and the facility placed in a shutdown cooling mode which does not rely on steam generators for cooling within 12 hours or at the maximum safe shutdown rate.

9. (This item revises item 6 of IE Bulletin 79-05.)

   Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

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10. Review and modify as necessary your maintenance and test procedures to ensure that they require:

    a. Verification, by inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

    b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

    c. A means of notifying involved reactor operating personnel whenever a safety-related system is removed from and returned to service.

11. All operating and maintenance personnel should be made aware of the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident.

12. Review your prompt reporting procedures for NRC notification to assure very early notification of serious events.

For Babcock and Wilcox pressurized water reactor facilities with an operating license, respond to Items 1, 2, 3, 4.a and 5 by April 11, 1979. Since these items are substantially the same as those specified in IE Bulletin 79-05, the required date for response has not been changed. Respond to Items 4.b through 4.d, and 6 through 12 by April 16, 1979.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, DC 20555.

For all other reactors with an operating license or constr ction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B 180225 (R0072); clearance expires 7-31-80. Approval was given under a blanket clearance specifically for identified generic problems.

Enclosures:

1. Preliminary Chronology of TMI-2 3/38/79
   Accident Until Core Cooling Restored.

2. List of IE Bulletins issued in last 12 months.

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Enclosure 1 to
IE Bulletin 79-05A
April 5, 1979

PRELIMINARY

CHRONOLOGY OF TMI-2 3/28/79 ACCIDENT UNTIL CORE COOLING RESTORED

TIME (Approximate)	EVENT
about 4 AM (t = 0)	Loss of Condensate Pump Loss of Feedwater Turbine Trip
t = 3-6 sec.	Electromatic relief valve opens (2255 psi) to relieve pressure in RCS
t = 9-12 sec.	Reactor trip on high RCS pressure (2355 psi)
t = 12-15 sec.	RCS pressure decays to 2205 psi (relief valve should have closed)
t = 15 sec.	RCS hot leg temperature peaks at 61[illegible] degrees F, 2147 psi (450 psi over saturation)
t = 30 sec.	All three auxiliary feedwater pumps running at pressure (Pumps 2A and 2B started at turbine trip). No flow was injected since discharge valves were closed.
t = 1 min.	Pressurizer level indication begins to rise rapidly
t = 1 min.	Steam Generators A and B secondary level very low - drying out over next couple of minutes.
t = 2 min.	ECCS initiation (HPI) at 1600 psi
t = 4 - 11 min.	Pressurizer level off scale - high - one HPI pump manually tripped at about 4 min. 30 sec. Second pump tripped at about 10 min. 30 sec.
t = 6 min.	RCS flashes as pressure bottoms out at 1350 psig (Hot leg temperature of 584 degrees F)
t = 7 min., 30 sec.	Reactor building sump pump came on.

TIME	EVENT
t = 8 min.	Auxiliary feedwater flow is initiated by opening closed valves
t = 8 min. 18 sec.	Steam Generator B pressure reached minimum
t = 8 min. 21 sec.	Steam Generator A pressure starts to recover
t = 11 min.	Pressurizer level indication comes back on scale and decreases
t = 11-12 min.	Makeup Pump (ECCS HPI flow) restarted by operators
t = 15 min.	RC Drain/Quench Tank rupture disk blows at 190 psig (setpoint 200 psig) due to continued discharge of electromatic relief valve
t = 20 - 60 min.	System parameters stabilized in saturated condition at about 1015 psig and about 550 degrees F.
t = 1 hour, 15 min.	Operator trips RC pumps in Loop B
t = 1 hour, 40 min.	Operator trips RC pumps in Loop A
t = 1-3/4 - 2 hours	CORE BEGINS HEAT UP TRANSIENT - Hot leg temperature begins to rise to 620 degrees F (off scale within 14 minutes) and cold leg temperature drops to 150 degrees F. (HPI water)
t = 2.3 hour	Electromatic relief valve isolated by operator after S.G.-B isolated to prevent leakage
t = 3 hours	RCS pressure increases to 2150 psi and electromatic relief valve opened
t = 3.25 hours	RC drain tank pressure spike of 5 psig
t = 3.8 hours	RC drain tank pressure spike of 11 psi - RCS pressure 1750; containment pressure increases from 1 to 3 psig
t = 5 hours	Peak containment pressure of 4.5 psig
t = 5 - 6 hours	RCS pressure increased from 1250 psi to to 2100 psi

TIME	EVENT
t = 7.5 hours	Operator opens electromatic relief valve to depressurize RCS to attempt initiation of RHR at 400 psi
t = 8 - 9 hours	RCS pressure decreases to about 500 psi Core Flood Tanks partially discharge
t = 10 hour	28 psig containment pressure spike, containment sprays initiated and stopped after 500 gal. of NaOH injected (about 2 minutes of operation)
t = 13.5 hours	Electromatic relief valve closed to repressurize RCS, collapse voids, and start RC pump
t = 13.5 - 16 hours	RCS pressure increased from 650 psi to 2300 psi
t = 16 hours	RC pump in Loop A started, hot leg temperature decreases to 560 degrees F, and cold leg temperature increases to 400 degrees F. indicating flow through steam generator
Thereafter	S/G "A" steaming to condensor Condensor vacuum re-established RCS cooled to about 280 degrees F., 1000 psi
Now (4/4)	High radiation in containment All core thermocouples less than 460 degrees F. Using pressurizer vent valve with small makeup flow Slow cooldown RB pressure negative

IE Bulletin No. 79-06 April 11, 1979

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

06

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S. E. Bryan, ROI:IE	
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E. M. Howard, SI:IE	
L. I. Cobb, XOMA:IE	
E. B. Blackwood, ROI:IE	
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

April 11, 1979

MEMORANDUM FOR: B. H. Grier, Director, Region I
J. P. O'Reilly, Director, Region II
J. G. Keppler, Director, Region III
K. V. Seyfrit, Director, Region IV
R. H. Engelken, Director, Region V

FROM: Norman C. Moseley, Director, Division of Reactor Operations Inspection, IE

SUBJECT: IE BULLETIN NO. 79-06, REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

The subject Bulletin should be dispatched for action on April 11, 1979, to all pressurized water power reactor facilities with an operating license except B&W facilities.

Facilities with a construction permit, Ft. St. Vrain, BWR and the B&W facilities with an operating license should receive the subject Bulletin for information only.

The draft letters to licensees are enclosed for your use in expediting and dispatching the Bulletin. The Bulletin text will be placed on Wylbur later today, at which time your office will be notified by telephone.

Norman C. Moseley, Director
Division of Reactor Operations
Inspection
Office of Inspection and Enforcement

Enclosure:
1. Draft Transmittal Letter to all Operating Licensees less BWR and B&W plants
2. Draft Transmittal Letter to Operating Licensees of B&W plants, Ft. St. Vrain and all Construction Permit Holders
3. IE Bulletin No. 79-06

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CONTACT: E. B. Blackwood, IE
49-28019

(Draft letter to all BWR power reactor facilities with an operating license and all power reactor facilities with a construction permit and Ft. St. Vrain.)

IE Bulletin No. 79-06

Addressee:

The enclosed Bulletin 79-06, is forwarded to you for information. No written response is required. If you desire additional information regarding this matter, please contact this office.

Sincerely,

Signature
(Regional Director)

Enclosure:
IE Bulletin No. 79-06
with Enclosures

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(Draft letter to pressurized water power reactor facilities other than B&W with an operating license.)

IE Bulletin No. 79-06

Addressee:

Enclosed is IE Bulletin No. 79-06, which requires action by you with regard to your pressurized water reactor facility(ies) with an operating license.

Based on our current understanding of the Three Mile Island accident sequence, and discussion with the designer of your pressurized water reactor, we have reason to believe that pressurizer level indication in your facility may not provide reliable information regarding level in the reactor coolant system under certain transient or accident condition. You should immediately instruct your operating personnel accordingly. In addition you should consider this possibility in responding to the enclosed bulletin.

Should you have any questions regarding this Bulletin or the actions required by you, please contac this office.

Sincerely,

Signature
(Regional Director)

Enclosure:
IE Bulletin No. 79-06
with Enclosures

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POOR ORIGINAL

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

April 11, 1979

IE Bulletin No. 79-06

REVIEW OF OPERATIONAL ERRORS AND SYSTEM MISALIGNMENTS IDENTIFIED DURING THE THREE MILE ISLAND INCIDENT

As previously discussed in IE Bulletin 79-05 and 79-05A, the Three Mile Island Nuclear Power Plant, Unit 2 experienced significant core damage which resulted from a series of events initiated by a loss of feedwater transient and apparently compounded by operational errors. Several aspects of the incident have generic applicability to all light water power reactor facilities, in addition to those previously identified as applicable to Babcock and Wilcox reactors. This bulletin is to identify certain actions to be taken by all other light water power reactor facilities with an operating license. Actions previously have been required of licensees with B&W reactors.

Action to be taken by licensees:

For all pressurized water power reactor facilities with an operating license except Babcock and Wilcox reactors:

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

   b. Operations personnel should be instructed to: (1) not override automatic action of engineered safety features without careful review of plant conditions; and (2) not make operational decisions based on a single plant parameter indication when a confirmatory indication is available.

   c. All licensed operators and plant management and supervision with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

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2. For pressurized water reactor facilities review the actions required by your operating procedures for coping with transients and accidents, with particular attention to:

   a. Recognition of the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially natural circulation capability.

   b. Operator action required to prevent the formation of such voids.

   c. Operator action required to enhance core cooling in the event such voids are formed.

3. For pressurized water reactor facilities that use pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, instruct operators to manually initiate safety injection when the pressurizer pressure indication reaches the actuation set point whether or not the level indication has dropped to the actuation set point.

4. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to cause containment isolation of all lines whose isolation does not degrade core cooling capability upon automatic initiation of safety injection.

5. For pressurized water reactor facilities for which the auxiliary feedwater system is not automatically initiated, prepare and implement immediately procedures which require the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which can be limited by such action.

6. For all pressurized water reactors, prepare and implement immediately procedures which:

   a. Identify those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators may utilize to determine that pressurizer power operated relief valve(s) are open, and

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b. Direct the plant operators to manually close the power operated relief block valve(s) when reactor coolant system pressure is reduced to the set point for normal automatic closure of the power operated relief valve(s) and the valve(s) fail to close.

7. Review the action directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features without careful review of plant conditions.

   b. Operators are provided additional information and instructions to not rely upon any one plant parameter but to also examine other related indications in evaluating plant conditions.

8. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (daily/shift checks, etc.) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

9. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

10. Review and modify as necessary your maintenance and test procedures to ensure that they require:

a. Verification, by test or inspection per technical specifications, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

c. Explicit notification of involved reactor operating personnel whenever a safety-related system is removed from and returned to service.

1. Review your prompt reporting procedures for NRC notification to assure very early notification of serious events.

For all pressurized water power reactor facilities with an operating license except Babcock and Wilcox reactors, respond to Items 1-11 within 14 days of the receipt of this Bulletin.

Reports should be submitted to the Director of the appropriate NRC Regional Office and a copy should be forwarded to the NRC Office of Inspection and Enforcement, Division of Reactor Operations Inspection, Washington, D.C. 20555.

For all other power reactors with an operating license or construction permit, this Bulletin is for information purposes and no written response is required.

Approved by GAO, B180225 (R0072); clearance expires 7/31/80. Approval was given under a blanket clearance specifically for identified generic problems.

LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-05	Malfunctioning of Circuit Breaker Auxiliary Contact Mechanism-General Model CR105X	4/14/78	All Power Reactor Facilities with an OL or CP
78-06	Defective Cutler-Hammer, Type M Relays With DC Coils	5/31/78	All Power Reactor Facilities with an OL or CP
78-07	Protection afforded by Air-Line Respirators and Supplied-Air Hoods	6/12/78	All Power Reactor Facilities with an OL, all class E and F Research Reactors with an OL, all Fuel Cycle Facilities with an OL, and all Priority 1 Material Licensees
78-08	Radiation Levels from Fuel Element Transfer Tubes	6/12/78	All Power and Research Reactor Facilities with a Fuel Element transfer tube and an OL.
78-09	BWR Drywell Leakage Paths Associated with Inadequate Drywell Closures	6/14/79	All BWR Power Reactor Facilities with an OL or CP
78-10	Bergen-Paterson Hydraulic Shock Suppressor Accumulator Spring Coils	6/27/78	All BWR Power Reactor Facilities with an OL or CP

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LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
78-11	Examination of Mark I Containment Torus Welds	7/21/78	BWR Power Reactor Facilities for action: Peach Bottom 2 and 3, Quad Cities 1 and 2, Hatch 1, Monticello and Vermont Yankee
78-12	Atypical Weld Material in Reactor Pressure Vessel Welds	9/29/78	All Power Reactor Facilities with an OL or CP
78-12A	Atypical Weld Material in Reactor Pressure Vessel Welds	11/24/78	All Power Reactor Facilities with an OL or CP
78-12B	Atypical Weld Material in Reactor Pressure Vessel Welds	3/19/79	All Power Reactor Facilities with an OL or CP
78-13	Failures In Source Heads of Kay-Ray, Inc., Gauges Models 7050, 7050B, 7051, 7051B, 7060, 7060B, 7061 and 7061B	10/27/78	All general and specific licensees with the subject Kay-Ray, Inc. gauges
78-14	Deterioration of Buna-N Components In ASCO Solenoids	12/19/78	All GE BWR facilities with an OL or CP
79-01	Environmental Qualification of Class IE Equipment	2/8/79	All Power Reactor Facilities with an OL or CP

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LISTING OF IE BULLETINS
ISSUED IN LAST TWELVE MONTHS

Bulletin No.	Subject	Date Issued	Issued To
79-02	Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts	3/2/79	All Power Reactor Facilities with an OL or CP
79-03	Longitudinal Weld Defects In ASME SA-312 Type 304 Stainless Steel Pipe Spools Manufactured By Youngstown Welding and Engineering Co.	3/12/79	All Power Reactor Facilities with an OL or CP
79-04	Incorrect Weights for Swing Check Valves Manufactured by Velan Engineering Corporation	3/30/79	All Power Reactor Facilities with an OL or CP
79-05	Nuclear Incident at Three Mile Island	4/1/79	All B&W Power Reactor Facilities with an OL
79-05A	Nuclear Incident at Three Mile Island	4/5/79	All B&W Power Reactor Facilities with an OL

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