LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3	0 5 0 0 0 3 6 2	1 of 0 8

Title (4)

REACTOR TRIP ON LOW STEAM GENERATOR LEVEL DUE TO PARTIAL LOSS OF POWER TO FEEDWATER CONTROL SYSTEM

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 1	0 6	8 9	8 9	0 0 1	0 1	0 7	1 2	8 9	NONE	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	Other (Specify in Abstract below and in text)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
H. E. Morgan, Station Manager	AREA CODE 7 1 4 3 6 8 - 6 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	E E	X F M R	S 2 5 0	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

X Yes (If yes, complete EXPECTED SUBMISSION DATE) — NO

Expected Submission Date (15): Month 1 2, Day 0 1, Year 8 9

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

At 2335 on 1/6/89, with Unit 3 at 98% power, the reactor tripped on low steam generator (SG) level after a partial loss of non-1E Uninterruptible Power Supply (UPS) power occurred which caused feedwater regulating valves to reduce flow to SG E089. This also resulted in actuation of emergency feedwater to SG E089. Emergency feedwater to SG E088 also actuated due to the resulting level "shrink" in SG E088, which is expected following a trip from high power. Since the Steam Bypass Control System was in manual to perform turbine valve testing, heat removal from the SGs was greater than normal. At 2336, as a result of the lower SG temperature, reactor coolant system (RCS) pressure decreased below the Safety Injection Actuation Signal (SIAS) setpoint (1806 psia), resulting in an SIAS actuation. There was no safety injection flow into the RCS since RCS pressure remained above the shutoff head of the injection pumps. All safety systems operated in accordance with design. At 0025 on 1/7/89, the plant was stabilized and all Engineered Safety Features were reset and lineups returned to normal.

Two of three non-1E UPS phases were lost because of a common fault in the associated inverter's constant voltage transformer (CVT) output windings. A temporary jumper between UPS ungrounded neutral and ground, which had not been properly removed during previous maintenance, may have contributed to the failure. The jumper was removed, the CVT was repaired, and the non-1E UPS was satisfactorily tested. Failure analysis of the CVT main core transformer is being conducted to determine the failure mechanism. The results of this evaluation will be discussed in a supplement to this LER.

Plant: San Onofre Nuclear Generating Station
Unit: Three
Reactor Vendor: Combustion Engineering
Event Date: 1-6-89
Time: 2335

A. CONDITIONS AT TIME OF THE EVENT:

Mode: 1, Power Operation

B. BACKGROUND INFORMATION:

The steam generator (EIIS Component Code SG) low level reactor trip provides protection for a loss of feedwater accident and assures that the design pressure of the Reactor Coolant System (RCS) (EIIS System Code AB) will not be exceeded due to loss of SG heat removal. The trip setpoint ensures that SG water inventory is sufficient such that the RCS will be cooled during start of the emergency feedwater system (EIIS System Code BA). A SG low level trip is initiated by any two-out-of-four independent level channels associated with either of two SG (E088 and E089). In addition, the Emergency Feedwater Actuation System (EFAS) associated with a SG (EFAS #1 for E089 and EFAS #2 for E088) is initiated at the low level trip setpoint for that SG.

The Feedwater Control System (FWCS) (EIIS System Code JB) regulates feedwater flow to the SGs by positioning feedwater control valves (EIIS Component Code FCV) and changing feed water pump (EIIS Component Code MFWP) speed in order to maintain SG level and replenish inventory removed as steam. Following a reactor trip or loss of power to the FWCS, the FWCS reduces feedwater flow to that necessary for initial latent heat removal by positioning the feedwater control valves to a preset, reduced flow, position.

Power is supplied to the FWCS from a non-safety related (non-1E) 120 VAC Uninterruptible Power Supply (UPS), (EIIS System Code EE). The UPS is supplied by an inverter (EIIS Component Code INVT), or by an alternate 480 VAC source via a regulator (EIIS Component Code 90) through automatic switching (EIIS Component Code ASU). The UPS provides 3 phase (A, B and C) power connected in a "Y" configuration with an ungrounded neutral. The inverter produces the 3 phase 120 VAC power in synchronization and phase with the alternate power source using two inverter (chopping) bridges and a constant voltage transformer (CVT) (EIIS Component Code XFMR). The CVT consists of two main core transformers which have dissimilar secondary windings, and filter assemblies which produce the correct 3 phase relationship to neutral. Control circuits provide voltage regulation and frequency control under varying loads, and synchronization to the alternate source.

C. DESCRIPTION OF THE EVENT:

1. Event:

At 2335 on January 6, 1989, with Unit 3 at 98% power, during the performance of weekly turbine valve testing, a partial loss of non-1E UPS power (phases B and C) occurred which caused the FWCS to position the SG E089 feedwater valves to their post-trip, reduced flow position. This resulted in a decrease in SG E089 level, which led to actuations of both the Reactor Protection System (RPS) (EIIS System Code JC) and EFAS #1 on low level in SG E089. EFAS #2 also actuated due to the resulting level "shrink" in SG E088, which is expected following a trip from high power.

The Steam Bypass Control System (SBCS)(EIIS System Code JI), which directs steam directly to the condenser (bypassing the main turbine) while maintaining SG pressure at a prescribed setpoint, had been manually set to perform turbine stop valve testing in accordance with procedures. Thus, following the reactor trip, the SBCS operated to maintain SG pressure approximately 100 psi below that which is normal. At 2336, as a result of the lower SG temperature (due to lower pressure), RCS pressure decreased below the Safety Injection Actuation Signal (SIAS) setpoint (1806 psia), resulting in an SIAS actuation. As per design, the SIAS initiated Containment Cooling Actuation Signal (CCAS) and Control Room Isolation Signal (CRIS) actuations.

The minimum RCS pressure reached during the transient (1717 psia) is greater than the shutoff head of the High Pressure Safety Injection (HPSI) pumps (EIIS System Code BQ)(EIIS Component Code P); therefore, no injection flow reached the RCS. The plant was stabilized and all Engineered Safety Features (ESF) were reset and lineups returned to normal at 0025 on January 7, 1989.

2. Inoperable Structures, Systems or Components that Contributed to the Event:

None.

3. Sequence of Events:

DATE	TIME	ACTION
1/6/89	2015	Operators commenced turbine valve testing and placed SBCS in manual.
1/6/89	2335	Partial loss of power occurred to non-1E UPS. Reactor tripped due to low level in SG E089. EFAS initiated.
1/6/89	2336	SIAS initiated due to low RCS pressure. CCAS and CRIS initiated from the SIAS.
1/6/89	2338	RCS pressure begins to stabilize from a low of 1717 psia.
1/7/89	0025	SIAS, CCAS and CRIS reset and alignment returned to normal. EFAS reset with manual control of feedwater. Operators complete Standard Post-Trip Actions and Reactor Trip Recovery procedures.
1/9/89	0525	Entered Mode 1 for Unit return to service.

4. Method of Discovery:

Control room alarms and indications alerted the operators of the reactor trip.

5. Personnel Actions and Analysis of Actions:

The operators responded properly to the reactor trip and stabilized plant conditions utilizing the Standard Post-Trip Actions and the Reactor Trip Recovery procedures.

The operators also responded properly by verifying that all EFAS, SIAS, CCAS, and CRIS components actuated as required.

6. Safety System Responses:

The RPS and EFAS operated in accordance with design, with no malfunctions noted. SIAS, CCAS (EIIS System Code BK) and CRIS (EIIS System Code VI), which actuated in response to the low RCS pressure, also operated in accordance with design. Additional information regarding safety system responses are described below:

Post-trip review of plant computer data revealed that SG E089 low level trip channels 1 and 4 initiated 1.4 and 0.4 seconds, respectively, after the reactor trip signal had been generated by channels 2 and 3. This response is considered normal; nonetheless, the level sensing lines were flushed, and no blockage or foreign material was found. This pattern of level response is indicative of the hydrodynamic effects which occur in the level sensing region of a SG when feedwater or steam flow are rapidly reduced. This was previously reported in LER 87-004-01 (Docket No. 50-361).

The HPSI discharge lines were pressurized to a maximum recorded value of 1556 psia. The pressure in one discharge line did not decrease as expected following securing the HPSI pumps. This has been attributed to a slight amount of RCS leakage into the discharge line due to reduced sealing force on the associated injection check valve (EIIS Component code V). RCS pressure reached its lowest value of 1717 psia and the HPSI discharge lines were pressurized to a maximum recorded value of 1556 psia; thus, the differential pressure across the injection check valve (potentially as low as 161 psid) was significantly less than the normal value of 1250 psid, resulting in less check valve sealing. Normal check valve sealing was restored when RCS pressure was returned to 2250 psia and the associated HPSI discharge line pressure was lowered to about 700 psia. Full resealing was achieved after the proper pressure differential was applied to the valve, in accordance with valve design.

Minor equipment anomalies observed following the reactor trip included: 1) one of two Nuclear Instrumentation Log Power indicators (EIIS Component Code JI) which did not completely trend with decreasing reactor power at its lower range; and 2) an alarm indicating lamp (EIIS Component Code IL) to one of four Core Protection Calculator channels did not illuminate. Neither of these anomalies were significant since they did not affect operability of any safety systems or the course of operator actions during this event. Corrective action was taken prior to returning the unit to service by recalibrating the Log Power channel indicator and replacing the failed lamp.

D. CAUSE OF THE EVENT:

1. Immediate Cause:

The FWCS positioned the SG E089 feedwater control valves to their post-trip, reduced flow positions, due to loss of non-1E UPS phases B and C. Both phases were lost because of a common fault in the associated inverter's CVT main core transformer output windings.

2. Contributing Cause:

Investigation following the trip identified an installed jumper between UPS ungrounded neutral and ground which had been erroneously left in place following maintenance. Although the failure mechanism of the CVT main core transformer as it relates to the presence of the jumper is not fully understood at this time, it is believed that the jumper may have contributed to the failure based upon testing of the UPS and subsequent evaluation.

The jumper was installed by two maintenance technicians (non-utility, non-licensed) on 6/15/88, during installation of temporary power to supply certain non-1E loads during maintenance of connections associated with the non-1E UPS. Although the temporary power cables were properly installed and documented in accordance with the procedure governing temporary system alterations, the technicians did not document in the work package the jumper installation contrary to this procedure. As a result, another technician (utility, non-licensed), who removed the temporary power, was not prompted to remove the jumper upon finishing the work.

3. Root Cause:

Our root cause evaluation of this event is continuing. The evaluation will include a failure analysis of the CVT main core transformer which will encompass the effects of the jumper. The evaluation consists of testing, engineering analysis and manufacturer review. Nondestructive testing of the faulted transformer has been completed but has not revealed the initiating failure mechanism. Destructive testing of the faulted transformer was then performed and has revealed that the CVT inner winding faulted to the core. Contamination (e.g. dirt, moisture, oil, etc.) of the windings has been determined not to have been a failure mechanism. Since no failure mechanism was identified by examination of the faulted transformer, testing of a nonfaulted transformer was performed. This examination did not result in identification of a failure mechanism. Testing will continue during the upcoming Unit 2 refueling outage utilizing an in-place transformer. The in-place testing will be conducted in an effort to investigate transformer/system interaction.

An engineering analysis is being performed to identify any atypical effects a neutral ground may have on the transformer controls. In addition, a manufacturer review is being conducted to identify if any manufacturing or design deficiencies may exist. Particular attention is being placed upon the type and thickness of insulation used in the transformer's windings. The final results of this evaluation will be discussed in a supplement to this LER.

E. CORRECTIVE ACTIONS:

1. Corrective Actions Taken:

a. The jumper was removed and the CVT main core transformer was replaced. Prior to returning Unit 3 to service, the inverter and non-1E UPS were tested and found to be operational.

b. This event has been reviewed with the technicians who had installed the jumper and appropriate disciplinary action has been taken.

c. This event has been reviewed with all appropriate maintenance personnel, emphasizing the importance of properly following the governing procedure for the use and control of temporary jumpers.

d. Although no deficiencies with the procedure for temporary system alterations and restorations were identified by a review conducted prior to Revision 0 of this LER, this procedure has been further reviewed and it has been determined that enhancements are not needed.

2. Planned Corrective Actions:

Pending results of our ongoing root cause evaluation, additional corrective actions will be taken, if necessary.

F. SAFETY SIGNIFICANCE OF THE EVENT:

There was no safety significance associated with the reactor trip since all safety and protective systems actuated by the RPS, SIAS, CCAS, CRIS, and EFAS #s 1 and 2 operated in accordance with their design.

G. ADDITIONAL INFORMATION:

1. Component Failure Information:

The inverter is a 217-290 VDC to 120/208 VAC, 3 phase, 60 Hz, 150 KVA unit, manufactured by Solid State Controls Incorporated under part list number 23778. A CVT main core transformer (item number TX801, part number 312744) is known to have failed.

2. Previous LERs on Similar Events (LER 3-87-011-02):

On 6/21/87 at 0258, with Unit 3 in Mode 1 at 100% power, the reactor automatically tripped on low SG water level. The low SG level was caused by an intermittent loss of power in one phase of a 120 VAC non-1E Instrument Bus which resulted in the inability to control feedwater and the consequent reduction in SG level. The loss of power was caused by a loose bolt connecting the B phase of instrument power to the main power bus of the non-1E UPS. The loose connection was corrected by tightening the bolt. The cause and corrective actions associated with that event are not applicable to the loss of the UPS phase B and C power on 1/6/89.

3. Previous Investigations of Non-1E UPS Inverter:

On 7/2/88, maintenance technicians missed discovering the jumper which was connected to the Non-1E UPS system down stream of the inverter during the first replacement of the transformer which had failed due to overheating. The jumper may have contributed to this failure as well. The presence of the jumper was not observed because replacement of the inverter did not include a detailed verification of Non-1E UPS system connections down stream of the inverter. In addition, on 10/23/88, during the second replacement of the transformer, trouble shooting efforts were increased and included a check of the Non-1E UPS system down stream of the inverter. A maintenance technician identified the presence of a neutral ground by meter reading. At this time, there was no direct observation of the jumper and the technician requested a maintenance order to investigate the ground. This equipment is nonsafety related and in accordance with procedure, maintenance was planned and given appropriate priority. Since the presence of a neutral ground does not render the inverter nonfunctional, the maintenance order was given a priority which would ensure that the problem was corrected within an appropriate period of time and when plant conditions permitted. However, 2 months later, the CVT main core transformer failed for the third time (resulting in the event being reported herein), prior to removal of the jumper. As corrective action, this event, including the missed opportunities to discover the jumper, has been reviewed with appropriate maintenance personnel.