TU ELECTRIC

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March 31, 1994

William J. Cahill, Jr.
Group Vice President

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES) - UNIT 2
DOCKET NO. 50-446
ENGINEERED SAFETY FEATURE ACTUATION
LICENSEE EVENT REPORT 446/94-003-00

Gentlemen:

Enclosed is the Licensee Event Report (LER) 94-003-00 for Comanche Peak Steam Electric Station Unit 2 "Initiation of Manual Reactor Trip Due to Main Turbine Load Swings."

Sincerely,

William J. Cahill, Jr.

By: [signature]
J. J. Kelley, Jr.
Vice President of Nuclear Engineering and Support

OB:tg

ENCLOSURE

cc: Mr. L. J. Callan, Region IV
Mr. L. A. Yandell, Region IV
Resident Inspectors, CPSES

IE22 1/1

Enclosure to TXX-94084

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO.3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
COMANCHE PEAK-UNIT 2	0 5 0 0 0 4 4 6	1 OF 11

Title (4)

INITIATION OF MANUAL REACTOR TRIP DUE TO MAIN TURBINE LOAD SWINGS

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Facility Names	Docket Numbers
03	05	94	94	- 003 -	00	03	31	94	N/A	05000
									N/A	05000

Operating Mode (9): 1

Power Level (10): 075

This report is submitted pursuant to the requirements of 10 CFR §: (Check one or more of the following) (11)

☐ 20.402(b)	☐ 20.405(c)	☒ 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, NRC Form 366A)
☐ 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	Area Code	Telephone Number
W.G. Guldemond, Manager, System Engineering	817	897-8739

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

Supplemental Report Expected (14)

☐ Yes (if yes, complete Expected Submission Date) ☒ No

Expected Submission Date (15): Month | Day | Year

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

On March 5, 1994, Comanche Peak Steam Electric Station (CPSES) Unit 2 was in Mode 1, with reactor power at 75 percent. The Balance of Plant Operator noticed Turbine/Generator (TG) load swings. Abnormal Operating Procedure was entered to stabilize the plant while the problem was being diagnosed. Because possible problems with the Electro-Hydraulic Control (EHC) Converter #1 were indicated, load control was switched to the Mechanical-Hydraulic Controller. The load swings temporarily subsided. The load swings returned and were increasing and the load was shifted to EHC Converter #2. This action did not stabilize the load swings. Without the ability to control the load swings the Unit Supervisor directed a manual reactor trip.After extensive troubleshooting, and correcting Unit 2 was restarted at 3:45 p.m., CDT on March 13, 1994. During the restart with the load at approximately 120 MWe, all four control valves abruptly closed. The BOP Operator immediately tripped the turbine.

It was determined that a feedback (Collins) coil in the EHC system had shorted/failed. Corrective actions involved troubleshooting of the EHC system and replacement of the feedback coil.

I. DESCRIPTION OF THE REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

Any event or condition that resulted in manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS)(EIIS:(JC)).

B. PLANT OPERATING CONDITIONS PRIOR TO THE EVENT

On March 5, 1994, Comanche Peak Steam Electric Station (CPSES) Unit 2 was in Mode 1, Power Operation, with reactor power at 75 percent (approximately 800 Megawatts (MWe).

On March 13, 1994, CPSES Unit 2 was in Mode 1, with reactor power at 18 percent (approximately 120 MWe).

C. STATUS OF STRUCTURES, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

There were no inoperable structures, systems, or components that contributed to the event.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROXIMATE TIMES

At 6:58 a.m., CDT on March 5, 1994, the Unit 2 Balance of Plant (BOP) Operator (utility, licensed) noticed Turbine/Generator (TG) (EIIS:TRB/GEN) load swings of approximately 16 Megawatts (MWe). Prior to these load swings TG load had been stable. Abnormal Operating Procedure ABN-401, "Main Turbine Malfunction", was entered to stabilize the plant while the problem was being diagnosed. During this time hydraulic pressure was observed to cycle slightly, indicating a possible problem with Electro-Hydraulic Control (EHC) Converter #1 (EIIS:(CNV)(JJ)).

At 8:09 a.m., CDT on March 5, 1994, the BOP Operator observed large load swings of approximately 76 MWe. On the advice of the System Engineer (utility, non-licensed) the Unit Supervisor (utility, licensed) shifted to Mechanical-Hydraulic Controller (MHC) (EIIS:(HCV)(JJ)) and secured power to EHC Converter #1. At 8:36 a.m., CDT, TG control was shifted to EHC Converter #2. Load was stabilized and was being controlled in Load Control Mode.

At 2:00 p.m., CDT on March 5, 1994, the BOP Operator observed load swings of approximately 50 MWe. The BOP Operator again attempted to mitigate the load swings by transferring control to MHC. Although the load swings temporarily subsided, at 2:10 p.m., CDT the load swings returned, increasing to approximately 100 MWe. The Unit Supervisor, (utility, licensed) based on his observations, believed that the MHC Controller had failed and shifted control to EHC Converter #2. The BOP Operator then lowered the load on EHC Converter #2. As he began this evolution load swings were in progress that were masking the actual transfer of control from MHC to EHC. As a result the TG load decreased to about 400 MWe because of the mismatch between MHC and EHC. Unable to control the load swings, the Unit Supervisor directed a Manual Unit 2 Reactor Trip at 2:29 p.m., CDT on March 5, 1994. At approximately 5:00 p.m., CDT on March 5, 1994, both motor driven auxiliary feedwater pumps were manually started; however, the turbine driven auxiliary feedwater pump automatically started due to 2 of 4 steam generator levels being less than 35.4 percent. All systems responded as expected, with the exception of the Source Range Nuclear Instrument Channel N31 which did not energize as required. CPSES Unit 2 was stabilized in Mode 3, Hot Standby.
An event or condition that results in an automatic or manual actuation of any ESF, including the RPS, is reportable within 4 hours under 10CFR50.72(b)(2)(ii). At 5:00 p.m., CDT on March 5, 1994, the Nuclear Regulatory Commission Operations Center was notified of the event via the Emergency Notification System.

During the eight days following the trip, troubleshooting was conducted that identified several factors which could have contributed to the event (see section IV for a detailed discussion of troubleshooting performed). The root cause of the TG load swings could not be determined. However, it was postulated that a combination of contributing factors caused the load swings. With these factors corrected the decision was made to restart Unit 2.

At approximately 3:40 p.m., CDT on March 13, 1994, Unit 2 was at 18 percent reactor power (approximately 120 MWe). At 3:47 p.m., CDT, all four control valves abruptly closed and the generator output breakers opened due to reverse power. The BOP Operator immediately tripped the turbine. Neither a reactor trip or an ESF actuation occurred (nor were required). The event was terminated and the plant stabilized. From this event, the root cause of the load swing event was determined; that the feedback (Collins) coil in the EHC system (EIIS:(JJ)) had shorted/failed (see section IV for a detailed discussion).

E. THE METHOD OF DISCOVERY OF EACH COMPONENT FAILURE, OR PROCEDURAL OR PERSONNEL ERROR

At 6:58 a.m., CDT on March 5, 1994, the Unit 2 BOP Operator noticed Turbine/Generator load swings of approximately 16 MWe. At 8:09 a.m., CDT the BOP Operator observed large load swings of approximately 76 MWe. Actions were taken to stabilize the load.

At 2:00 p.m., CDT on March 5, 1994, the BOP Operator observed load swings of approximately 50 MWe. The load swings temporarily subsided. At 2:10 p.m., CDT the load swings returned, increasing to approximately 100 MWe. Unable to control the load swings the Unit Supervisor directed a manual trip.

At 3:47 p.m., CDT on March 13, 1994, all four control valves abruptly closed and the generator output breakers opened due to reverse power. The BOP Operator immediately tripped the turbine.

II. <u>COMPONENT OR SYSTEM FAILURES</u>

A. FAILURE MODE, MECHANISM, AND EFFECT OF EACH FAILED COMPONENT

The cause of the TG load swings could not be initially determined. However, during the eight days following the event (trip), troubleshooting identified several factors which could have contributed to the event. The details of the troubleshooting is described in section IV of the LER. On March 13, 1994, during the restart of Unit 2 all four control valves abruptly closed. The feedback coil in the EHC system had shorted/failed. The failure cause of the feedback coil has not been determined. This appears to be an unusual failure for this component and is considered to be an isolated occurrence. The feedback coil has been sent to the vendor for a failure analysis.

B. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

The cause of feedback coil failure is unknown, failure analysis is being conducted by the vendor.

C. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY FAILURE OF COMPONENTS WITH MULTIPLE FUNCTIONS

Not applicable - there were no failed components with multiple functions that affected this event.

D. **FAILED COMPONENT INFORMATION**

a) Collins Coil

Manufacturer: G. L. Collins Corporation
Model: Linear Motion Transducer
Serial Number: 180295
Tag Number: 2-SE1LC005F01

III. ANALYSIS OF THE EVENT

A. **SAFETY SYSTEM RESPONSES THAT OCCURRED**

The following safety system actuations occurred as expected as a result of this event.

Reactor Protection System
Auxiliary Feedwater System (AFW)(EIIS:BA).

B. **DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY**

At 2:40 p.m., CDT on March 5, 1994. Source range instrument channel N31 did not energize as required. At 3:35 a.m., CDT on March 6, 1994, N31 was returned to service.

C. **SAFETY CONSEQUENCES AND IMPLICATIONS OF THE EVENT**

This event has been analyzed in Chapter 15.2.3 and 15.1.3 of the Final Safety Analysis Report (FSAR) for Turbine Trip. The FSAR provides analysis of a turbine trip without taking credit for a reactor trip or the initiation of AFW. In this event a turbine trip occurred coincident with a reactor trip and the initiation of AFW. The reactor trip and the response to the plant trip were normal and within design limits. Based on this discussion it is concluded that this event did not adversely affect the safe operation of CPSES Unit 2 or the health and safety of the public.

IV. CAUSE OF THE EVENT

The root cause of the Turbine/Generator load swings could not initially be determined. During the eight days (after the trip) troubleshooting was conducted that identified several potential causes. The troubleshooting performed and the corrective actions taken are discussed below.

TROUBLESHOOTING

Troubleshooting focused on three general areas which could have caused or contributed to the event: (A) Electronic Control Failures; (B) Hydraulic Failures; and (C) Grid Fluctuations. The following potential causes/contributing factors of the event were evaluated.

A) ELECTRONIC CONTROLS FAILURE

1. EHC controller, MHC controller, EHC valve lift controller out of calibration:

   Loop calibrations were performed, and the loops were found to be within specification, requiring minor adjustments. This was not considered to be a contributing factor to the event.

2. Speed Sensor or Controller affecting the EHC controller causing load fluctuations:

   The Speed Target Unit (STU) data was collected from the Data Acquisition System. The STU data was reviewed and found to be normal during the time frame of the event. The STU sensors were inspected with damage found on the outer ring of the magnet disk along with some sensor damage. The magnet disk and the speed sensors were replaced. This was not considered to be a contributing factor to the event.

B) HYDRAULIC FAILURE

1. Erratic EHC Pump Operation:

   EHC pumps A, B and C were dissembled and inspected. Critical dimensions were taken per vendor recommendations. No internal pump damage was found. During CPSES Unit 1 refueling outage, Unit 1 pumps revealed signs of rotation and anti-rotational devices were installed to eliminate the problem. The Unit 2 pump diffusers were inspected for signs of rotation. No evidence of the pump rotation was found. As a precautionary measure anti-rotational devices on all three Unit 2 EHC pumps were installed.

Troubleshooting of each pump is as follows:

a) EHC Pump A; the gasket between the second and third stage diffuser pushed away from the sealing surface. This could have effected the performance of the pump and the stability of the control fluid pressure. The outer diameter (OD) of the third stage impeller was measured and found to be the same dimension as the second stage, instead of being around 6 millimeters (mm) larger, as specified. The undersized impeller was not considered to be a contributing factor to the load swings. In the interim, the turbine vendor has concluded that stable operation will continue with this condition.

b) EHC Pump B; approximately 50 percent of the high pressure (HP) pump discharge flange gasket was missing. This could have significantly affected the pump's performance and the stability of the control fluid pressure. However, EHC Pump B was not operating during this event, and as such was not considered to be a contributing factor. The gasket was replaced.

c) EHC Pump C; the gasket between the second and third stage diffuser was found separated in two places but with no significant loss of sealing. The OD of the third stage impeller was measured and found to be the same dimension as the second stage, instead of being 6mm larger, as specified (similar to EHC Pump A). The undersized impeller was not considered to be a contributing factor to the load swing event. In the interim, the turbine vendor has concluded that stable operation will continue with this condition.

d) It was postulated that the degraded EHC fluid (previously determined to be contaminated with ethylene glycol) could have contributed to the gasket failures. The gasket material removed from the pumps did not exhibit any sign of deterioration and the EHC fluid manufacturer stated the fluid should not affect the gasket material used in the EHC system. A sample of fluid was sent to the vendor for confirmation.

The EHC pumps were reassembled under the vendor's direction. The pump performance was satisfactorily verified prior to restart of the TG.

Text (if more space is required, use additional NRC Form 366A's) (17)

2. EHC Pump Discharge Check Valve Malfunction:

   All six EHC Pump d'scharge check valves were visually inspected and checked for freedom of movement. The check valves passed the visual inspection and demonstrated the ability to contain approximately 30 feet head of EHC fluid. One check valve's (2EH-0002) movement was sticky. The check valve's packing was adjusted, correcting the problem. This was not considered to be a contributing factor to the event.

3. EHC Pump Minimum Flow Line Check Valve Malfunction:

   All three check valves were checked for freedom of movement. Two valves were found to have sticky operation. The two valves were repacked. This condition was not considered to be a contributing factor to the event.

4. System Leaks:

   The EHC system was walked down and inspected for leaks. No major external leakage was observed. This was not considered to be a contributing factor to the event.

5. EHC Fluid Degradation and Air Entrainment Caused By Ethylene Glycol Contamination:

   There were no evolutions which would have introduced additional air into the EHC systems. The condition of the fluid did not cause the load swings, but may have contributed to the severity of the load swings by inhibiting the overall control system. The EHC fluid was replaced to conform with vendor specifications.

6. EHC System Cleanliness:

   During the removal of the EHC fluid, a small amount of construction debris was found in the sump. There was a small piece of cleaning paper found in the cuno filter upstream of the Converters, and a small piece of plastic found in the #4 HP Control Valve pre-control pilot valve. While this did not prevent movement, it may have slightly slowed movement of the valve. System cleanliness is not believed to be a contributing cause of the load swings. EHC system cleanliness issue was resolved during EHC fluid replacement.

7. Control Valve Erratic Behavior:

An initial set of Mechanical and Electrical Valve Curves were taken. These curves showed that the control valves were operating normally. It was noted that the #1 Control Valve appeared to initially lead and then slightly lag the other three valves. All four HP Control Valves pre-control pilot valve assemblies were inspected. There were no signs of failure but it did exhibit signs of normal wear. This was not believed to be a contributing factor to the load swings. A set of Mechanical and Electrical curves were taken and valve performance verified prior to restart of the TG.

An inspection of the feedback linkage pivot pins for the #1 Control Valve was conducted. The pivot pins have a brass bushing around the pin. When the brass bushing is worn the valve may not respond appropriately to the control signal, thus causing the valve to hunt for position. The inspection revealed that the bushings in the #1 Control Valve were scored. All three bushings in the #1 Control Valve were replaced and the valve retested successfully. This could have been a contributing factor to the load swings.

8. Erratic Solenoid Valve Operation:

The ground detector revealed a ground on the power supply bus to the Turbine Trip System Cabinet. Testing was performed to ensure these power supply grounds are not causing the load swings prior to restart of TG. No grounds were identified in the power supply to the Turbine Trip System Cabinets. This area was not considered to be a contributing factor of the load swings.

C) GRID FLUCTUATION

The grid was not the source of the load swings based on the lack of fluctuation in Unit 1.

ROOT CAUSE

At 3:47 p.m. on March 13, 1994, during the restart of Unit 2 TG, all four Control Valves abruptly closed. The generator output breakers opened due to reverse power. The BOP Operator immediately tripped the turbine. Neither reactor trip nor ESF actuation occurred (nor were required). From this event, the root cause of the load swings was determined. The feedback (Collins) coil in the EHC System had shorted/failed. The feedback coil is a linear motion transducer that provides feedback to the valve lift controller to maintain Control Valve position while controlling on EHC. Failure of this coil produces clearly identifiable symptoms. In this case the coil was apparently experiencing intermittent failures which did not clearly identify it as being the cause until it completely failed. Electrical Valve Curve tests had been previously performed to determine if a problem in this circuit existed. While the tests would disclose a feedback coil failure, they did not do so in this case because of the intermittent nature of the failure.

V. CORRECTIVE ACTIONS

The Unit 2 linear motion transducer (Collins Coil) was replaced, and the EHC Unit was returned to service. The failed Collins Coil was sent to the turbine vendor for a failure analysis. Failure of this coil has previously occurred at other utilities; however, these failures resulted in an open circuit instead of a short. The intermittent failure and subsequent shorting of this coil was considered unusual and an isolated case. Nevertheless, TU Electric will review the failure analysis and determine appropriate actions for both Units. To further ensure reliability the Collins Coil in the other Unit 2 EHC converter will be tested during a future outage.

With respect to corrective actions taken during the troubleshooting process, TU Electric has or will perform the following actions to prevent recurrence:

a) The damaged gaskets in Unit 2 EHC pumps were replaced. The performance of Unit 1 EHC pumps was also reviewed. Current Unit 1 EHC pump performance did not reveal gasket problems, no action was taken for Unit 1 EHC pumps.

b) The entire volume of EHC fluid was replaced with new fluid meeting the vendor's specification. A sample of the degraded fluid was sent to the vendor to ensure that the degraded fluid did not have an affect on the gaskets in the EHC system. TU Electric will evaluate the need for additional corrective actions, if warranted, upon receipt of the fluid analysis from the vendor.

c) All three brass bushings which were found scored in the #1 Control Valve were replaced and the valve retested successfully. The brass bushings in the other control valves will not be replaced at this time (for both units) based on satisfactory performance of these valves.

d) The failure of source range channel N31 was traced to a fault card in Train A Solid State Protection System (EIIS:(JG)). The fault card which feeds the Train A P-10 source range auto-block was replaced.

VI. PREVIOUS SIMILAR EVENTS

There have been no other previous LERs which dealt with Turbine/Generator load swings causing a reactor trip.