NON-PUBLIC?: N
ACCESSION #: 9502010030
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Browns Ferry Nuclear Plant (BFN) Unit 2 PAGE: 1 OF 6

DOCKET NUMBER: 05000260

TITLE: Unit 2 Scram From 54 Percent Power Caused By Balance Of
Plant Equipment Failure
EVENT DATE: 12/02/94 LER #: 94-013-01 REPORT DATE: 01/19/95

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 54

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Steven W. Austin, Compliance TELEPHONE: (205) 729-2070
Licensing Engineer

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: JJ COMPONENT: TIS MANUFACTURER: M235
REPORTABLE NPRDS: N

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On December 2, 1994 at 0717 hours, Unit 2 received a full automatic scram from 54 percent reactor power. The scram was generated by a main generator turbine trip with the first stage turbine pressure greater than 154 psig. The turbine trip was caused by an invalid loss of main generator stator cooling water signal. The scram resulted in a low reactor water level which caused the isolation/actuation engineered safeguards (ESF) and reactor protection (RPS) systems. The affected ESF and RPS systems were returned to standby readiness by 0729 hours. The root cause of the event was mechanical degradation of the Main Generator Stator Cooling Water system temperature switch. The switch experienced setpoint drift which caused it to prematurely actuate. TVA will issue a procedure for calibration of the stator cooling water temperature switch. Additionally, TVA will evaluate balance of plant devices capable of causing turbine generator trips and ensure that the procedural guidance

for calibration is adequate. Finally, TVA will evaluate other balance of plant devices to Bee if due to its age, replacement is required. TVA is reporting this event in accordance with 10 CFR 50.73 (a)(2)(iv), as any event or condition that resulted in manual or automatic actuation of any ESF including the reactor protection system.

END OF ABSTRACT

I. PLANT CONDITIONS

Unit 2 was at approximately 54 percent power (1763 megawatts thermal). Units 1 and 3 were shutdown and defueled.

II. DESCRIPTION OF EVENT

A. Event

On December 2, 1994 at 0717 hours, Unit 2 received a full automatic scram from 54 percent reactor power. The scram was generated by a main generator turbine TB! trip with the first stage turbine pressure greater than 154 psig. The turbine trip was caused by an invalid loss of main generator stator cooling water signal JJ!. The scram resulted in a low reactor water level signal of which caused actuation or isolation of the following Primary Containment Isolation System JE!(PCIS) systems/components.

o PCIS group 2, Shutdown cooling mode of Residual Heat Removal BO! system; Drywell floor drain isolation valve, Drywell equipment drain BUMP isolation valve WP!

o PCIS group 3, Reactor Water Cleanup CE!

o PCIS group 6, Primary Containment Purge and Ventilation JM!; Unit 2 Reactor Zone Ventilation VB!; Refuel Zone Ventilation VA!: Standby Gas Treatment (SGT) BH! system; Control Room Emergency Ventilation (CREV)VI!

o PCIS group 8, Transverse Incore Probe IG! withdrawal

On December 2, 1994, at approximately 0716 hours, the stator cooling system TJ! alarm was received in the Unit 2 Main Control Room. Approximately 10 seconds later a stator cooling failure alarm was received. Control room indication did not

identify any stator cooling water problems. The Unit Operator (UO), utility licensed, initiated a load reduction on the stator. Additionally, an Assistant Shift Operations Supervisor (ASOS), utility licensed, was dispatched to the stator cooling water alarm panel to investigate.

Approximately 70 seconds after the initial alarm the main generator TA! and main turbine tripped, followed immediately by a reactor scram.

The affected Systems were returned to standby readiness by 0729 hours. All systems responded as expected during the reactor scram.

This event is reportable in accordance with 10 CFR 50.73 (a)(2)(iv), as any event or condition that resulted in manual or automatic actuation of any engineered safety feature including the reactor protection system.

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

None.

C. Dates and Approximate Times of Major Occurrences:

December 2, 1994 at 0717 CST The Unit 2 Reactor received a full scram from a main turbine trip.

December 2,, 1994 at 0729 CST The PCIS actuations were reset. SGT and CREV systems are returned to standby readiness.

December 2, 1994 at 1001 CST TVA made a 4 hour nonemergency notification to NRC in accordance with 10 CFR 50.72 (b)(2)(ii).

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

The Unit 2 Operator received a Stator Cooling System Abnormal alarm followed by a Stator Cooling Water Failure alarm in the Unit 2 Main Control Room. These alarms were followed by alarms associated with the full reactor scram.

F. Operator Actions:

Operator actions taken during this event were as expected. At the onset of the event an ASOS was dispatched to the Stator Cooling Water panel to investigate the alarms. Additionally, the UO began to reduce main generator stator load to reduce stator current and thus lower the stator cooling heat load. Upon receiving the reactor scram, the reactor operator performed the actions described by Abnormal Operating Instruction "Reactor Scram," bringing the reactor to hot standby condition. The plant responded to the scram as expected.

G. Safety System Responses:

The safety systems listed in section IIA of this report responded to the reactor scram as designed.

III. CAUSE OF THE EVENT

A. Immediate Cause:

The immediate cause of the generator and main turbine trip was a premature operation of the stator cooling water high temperature switch TIS!. This was followed by a reactor scram.

B. Root Cause:

The root cause of the event was a mechanical degradation of the stator cooling water temperature switch. The degradation caused a setpoint drift in the conservative direction thus premature operation of the temperature switch. At the time of the trip the indicated cooling water temperature was approximately 112 degrees F while the normal trip setpoint is 179 degrees F. The initial post event field verification of the setpoint indicated that the switch would actuate at approximately 126 degrees F. Subsequent additional testing indicated that the actual setpoint had drifted to approximately

115 degrees F.

C. Contributing Factors:

Contributing in the event was that during a routine calibration on October 6, 1994, the trip setpoint was verified at the required 179 degrees F. However, the observed reset dead band was unusually high. Post trip calibration found that at 174 degrees F the reset dead band was approximately 94 degrees F. This dead band exceeds the normal dead band of 10-12 degrees. The large dead band gave indication that the switch actuation mechanism may have been unreliable. There is no specific guidance for the calibration of this instrument with regard to the dead band. Had guidance been available that specified a dead band the instrument would have been replaced during the previous calibration.

The single-failure vulnerability of the turbine generator control and protection system components, places the plant at risk for single failures that can cause undesirable trips similar to the event described in this report.

IV. ANALYSIS OF THE EVENT

BFN is analyzed in Chapter 14 of the Updated Final Safety Analysis Report for a turbine trip/reactor scram assuming a starting point of greater than 100% reactor power and associated steam flow. The most severe transient for a full power generator trip occurs if the turbine bypass valves fail to open. In this event, the trip occurred at 54 percent power. Additionally, affected components (including the turbine bypass valves) functioned as designed. Thus this event is bounded by the plant safety analysis.

V. CORRECTIVE ACTIONS

A. Immediate Corrective Actions:

The affected systems were restored to operable status. The temperature switch was replaced prior to the restart of the unit.

B. Corrective Actions to Prevent Recurrence:

1. TVA will issue a specific instruction for the calibration

of the stator cooling water temperature switch.1_/ This instruction is scheduled for issuance by April 11, 1995. The below corrective action describes actions being taken for other similar type procedures.

2. TVA will evaluate balance of plant devices capable of causing turbine generator trips and determine if procedural guidance for calibration is adequate.1_/ This evaluation is scheduled for completion by May 29, 1995.

3. TVA will evaluate other balance of plant devices capable of causing turbine generator trips or equipment operation to determine if the equipment will need replacement due to its age.1_/ This evaluation is scheduled for completion by April 24, 1995.

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1_/ TVA does not consider these actions to be Regulatory Commitments. That is, they are not actions required to restore compliance with obligations. Obligation means an action that is a legally binding requirement imposed through applicable rules, regulations, orders, and licenses.

The above actions are not necessary to preserve compliance with obligations. They are measures taken to minimize recurrence of reactor scrams.

VI. ADDITIONAL INFORMATION

A. Failed Components:

A Mercoid model DA 38-3 wet fluid filled capillary design temperature switch failed. The temperature switch experienced a setpoint drift which caused the switch to prematurely actuate.

B. Previous LERs on Similar Events:

No previous BFN events were identified in which the stator cooling water temperature switch was the cause of a unit trip and reactor scram.

VII. Commitments

None.

Energy Industry Identification System (EIIS) system and component codes
are identified in the text with brackets (e.g., XX!).

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