TVA

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

Joseph R. Bynum
Vice President, Nuclear Operations

February 1, 1991

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 2 - DOCKET NO. 50-328 - FACILITY OPERATING LICENSE DPR-79 - LICENSEE EVENT REPORT (LER) 50-328/91001

The enclosed LER provides details concerning a high-high steam generator level initiated feedwater isolation and subsequent automatic start of the auxiliary feedwater system, which resulted from anomalies in the main turbine electrohydraulic control system. Also included in this report are details concerning an entry into Limiting Condition for Operation 3.0.3 when two rod position indicators in the same rod bank deviated from their corresponding demand position indicator by greater than 12 steps during plant stabilization from the above transient.

These events are being reported in accordance with 10 CFR 50.73(a)(2)(iv) as an event that resulted in an automatic actuation of engineered safety features and 10 CFR 50.73(a)(2)(i) as an operation prohibited by technical specifications.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

J. R. Bynum

Enclosure
cc: See page 2

IE22

cc (Enclosure):

Mr. J. N. Donohew, Project Manager
U.S. Nuclear Regulatory Commission
One White Flint, North
11555 Rockville Pike
Rockville, Maryland 20852

INPO Records Center
Institute of Nuclear Power Operations
1100 Circle 75 Parkway, Suite 1500
Atlanta, Georgia 30339

NRC Resident Inspector
Sequoyah Nuclear Plant
2600 Igou Ferry Road
Soddy Daisy, Tennessee 37379

Mr. B. A. Wilson, Project Chief
U.S. Nuclear Regulatory Commission
Region II
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

NRC Form 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

Approved OMB No. 3150-0104 Expires 4/30/92

LICENSEE EVENT REPORT (LER)

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TITLE (4) Automatic feedwater isolation and subsequent auxiliary feedwater system start as the result of a high-high steam generator level and LCO 3.0.3 entry for more than one RPI per bank inoperable.

EVENT DAY (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 5 0 0 0
0 1	0 3	9 1	9 1	0 0 1	0 0	0 2	0 1	9 1		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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)	XX 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)	XX 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
Russell R. Thompson, Compliance Licensing	AREA CODE 6 1 5 8 4 3 - 7 4 7 0

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) | X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On January 3, 1991, at 1516 Eastern standard time (EST) with Unit 2 in Mode 1, a feedwater isolation (FWI) and subsequent automatic start of auxiliary feedwater occurred. The FWI was the result of a high-high steam generator level signal from Loop No. 4. The high-high level setpoint was reached following the inadvertent closure of the main turbine governor valves. The governor valves closed during attempts to reset the turbine electrohydraulic control (EHC) system following an automatic turbine runback. The turbine EHC system was receiving an artificially high input for turbine impulse pressure, which was caused by a dampening valve that had vibrated closed in the impulse pressure transmitter sense line. Administrative controls have been initiated that prohibit the use of the turbine control circuitry, which utilized the turbine impulse pressure input.

On January 4, 1991, at 0512 EST with Unit 2 stabilized in Mode 2, Limiting Condition for Operation (LCO) 3.0.3 was entered when two rod position indicators in the same bank deviated from the demand position indicators by greater than 12 steps. The deviations were the result of temperature changes and rod movement following the turbine trip. Temperature was stabilized, the control rods were withdrawn slightly, and the RPIs returned to indicating within 12 steps of the demand indicators. LCO 3.0.3 was exited at 1002 EST. An evaluation will be conducted in an effort to prevent future entries into LCO 3.0.3 as a result of RPI drift.

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

DESCRIPTION OF EVENT

On January 3, 1991, at approximately 1517 Eastern standard time (EST), Unit 2 experienced a high-high steam generator level feedwater isolation (FWI) signal (EIIS Code JE) and subsequent automatic start of the auxiliary feedwater system (EIIS Code BA). These events were the results of anomalies in the main turbine electrohydraulic control (EHC) system (EIIS Code IT). Unit 2 was in the process of recovering from an automatic turbine runback when these events occurred. Before these events, Unit 2 was operating in Mode 1 (100 percent power, reactor coolant system [RCS] pressure at 2,235 pounds per square inch gauge [psig], and average RCS temperature at 578 degrees Fahrenheit [F]).

At approximately 0512 EST on January 4, 1991, with Unit 2 stabilized in Mode 2 (0 percent reactor power, RCS pressure at 2,235 psig, and average RCS temperature at 547 degrees F), Limiting Condition for Operation (LCO) 3.0.3 was entered when two rod position indicators (RPIs) (EIIS Code AA) deviated from the corresponding demand position indicator by greater than 12 steps. The action provisions of LCO 3.1.3.2 are limited to one RPI per bank being inoperable.

At 1300 EST on January 3, 1991, the balance of plant (BOP) reactor operator (RO) had noticed a change in the flow from the No. 3 heater drain tank (HDT) pumps (EIIS Code SN). The change in flow was detected by observing a narrowing of the No. 3 HDT flow recorder trace. The BOP RO requested an assistant unit operator (AUO) to investigate. The AUO observed a high level in the No. 3 HDT. The normal level control valves (LCV-6-106A and 106B) appeared to be full open with the bypass to condenser valve (LCV-6-105B) bumping open periodically, approximately one-half inch. When the main control room (MCR) was informed of the bypass valve opening, they became concerned that if the bypass open limit switch actuated, it would initiate an automatic turbine runback and associated secondary side transient. The unit crew, with concurrence from the shift operations supervisor (SOS), decided to reduce load manually in an attempt to prevent an automatic turbine runback. The crew began a load reduction at 1321 EST.

During the manual load reduction, the No. 3 HDT bypass valve opened enough to initiate an automatic runback. This runback started and stopped several times as the bypass valve bumped open and closed. This runback continued and finally stabilized with the turbine at 60 percent governor valve position and reactor power at 72 percent at approximately 1414 EST.

At 1450 EST, when plant systems were verified to have stabilized, the crew again began reducing reactor power to 65 percent in order to secure the No. 3 HDT pumps and to make repairs on LCV-6-106A and 106B.

Because the turbine had experienced an automatic runback, the governor valve position limiter was now in control of the turbine governor valves. To initiate a normal turbine load reduction, it was necessary to regain normal EHC control of the governor valves. The BOP RO had performed this activity on the simulator, but had never performed it at the plant. After the unit crew members discussed the issue, it was decided to transfer EHC control to "IMP IN" and then back to "IMP OUT" to reset the control panel indications to reflect actual turbine load. (IMP IN utilizes turbine impulse pressure, turbine speed, a reference turbine load, and generator electrical output to control turbine load. IMP OUT utilizes the reference turbine load, turbine speed, and governor valve position as inputs to control turbine load.) This process had been routinely performed in the past for similar runbacks, and is an accepted method based on vendor input and operator training.

At approximately 1510 EST the RO pushed the IMP IN button, and the reference and setter indicators appeared to be responding normally in that they were flashing during the reset process. The operators immediately observed that the governor valve position indicators were showing a valve insertion. They also noted that the megawatt load was decreasing. The senior reactor operator (SRO) immediately informed the RO on the EHC panel of his observations. The RO depressed the IMP OUT button in attempt to make the EHC system go back to IMP OUT to stop governor valve movement. This did not stop the valve movement. Anticipating a unit trip the crew immediately began preparations to monitor system performance prior to and during the trip.

As the governor valves closed and the load dropped, control rods began automatically inserting in attempt to reduce RCS average temperature, which was above its programmed value because of the mismatch between reactor and turbine power. The steam dump valves began opening to compensate for the rapid turbine load reduction. When the governor valves indicated full closed (approximately 1511 EST), reactor power had already been reduced below P-9 (50 percent), which would allow a turbine trip without a reactor trip.

At this point the Unit 1 SRO (who had the control room command function) noticed a large deviation between steam generator feedwater flow and steam flow. Feedwater flow was approximately one million pounds per hour higher than steam flow. This was the expected control system response to the low level that occurred from severe steam generator shrink when the turbine governor valves closed at a rate of approximately 200 percent per minute. However, the Unit 1 SRO knew from experience that when this large volume of feedwater was heated in the steam generator a high level could result. He brought this to the attention of the Unit 2 SRO and BOP RO, at which time B main feedwater pump was placed in manual and unloaded in an effort to prevent a feedwater isolation from high-high steam generator level.

At 1517 EST, while manually reducing the load carried by the B main feedwater pump, the turbine received a generator reverse power trip signal. This is an expected consequence of the fact that the turbine steam supply valves were closed. This initiated a turbine trip and power circuit breaker (PCB) open signal. The turbine first out annunciator indicated that the turbine tripped on low auto stop oil pressure and turbine overspeed. This was determined to be a normal indication on a reverse power trip without a prior turbine trip, because no generator trips are indicated on the first out panels.

Shortly after the turbine trip, steam generator No. 4 level reached approximately 82 percent, initiating a high-high steam generator level FWI (setpoint of 81 percent). The FWI tripped both main feedwater pumps, which automatically started the auxiliary feedwater system. The lead RO then took manual control of the control rods and brought reactor power down to approximately 2 percent to ensure the unit was maintained within auxiliary feedwater capacity.

At this point, the operator proceeded to stabilize the unit and shutdown all unnecessary equipment. The unit was stabilized in Mode 2 at 0 percent power, with control rods at 210 steps on control bank D.

By the time the next shift crew had assumed shift, Xenon had begun to burn out and periodic boration was required to hold power level constant. In preparation for the upcoming power increase and to prevent periodic boration and subsequent dilution during the power increase, the crew decided to use control rods to offset the Xenon burnout.

At 0238 EST on January 4, 1991, the control rods nad been inserted to 194 steps (it had been decided earlier to go to approximately 150 steps on D bank). The RO observed that RPI M-4 was indicating 207 steps, which exceeds the 12-step deviation limit of Technical Specification LCO 3.1.3.2a. This LCO action was entered and an immediate attention work request written to troubleshoot and repair.

Control rod insertion was continued and the RPIs monitored closely, because all of the control bank D RPIs were indicating approximately a 10 step deviation from the step counter. At 0512 EST, the RO observed that H-4 control rod RPI had drifted up and was deviating from the demand counter indication of 167 steps by more than 12 steps. Both the M-4 and H-4 RPIs were in control bank D. Because the technical specification only allows one RPI to be inoperable per bank, this resulted in an entry into LCO 3.0.3 at 0512 EST. Corrective actions were pursued, all RPIs were within the allowed deviations, and LCO 3.0.3 exited at 1002 EST on January 4, 1991.

CAUSE OF THE EVENT

The automatic turbine runback was the result of high level in the No. 3 HDT, which had caused condensate flow to be diverted to the condenser. Investigation revealed that No. 3 HDT Level Control Valve LCV-6-106B failed to properly control level in the No. 3 HDT as the result of binding. Binding of the valve has been attributed to magnetite buildup, which decreased operating clearance, and improper valve reassembly that incorrectly oriented the valve plug to the valve body. The improper reassembly of the valve is attributed to an isolated case of failing to follow the reassembly procedure.

The cause of the closure of the four turbine governor valves during the attempt to reset the EHC system is attributed to a mismatch between generator electrical output and sensed turbine impulse pressure in the IMP IN control circuit. Troubleshooting of Pressure Transmitter PT-47-13 (the impulse pressure channel feeding the EHC system) approximately four hours after the trip, indicated that PT-47-13 still had a 4.82-volt output (40-50 percent indication). This output was slowly decreasing, indicating a bad transmitter or a closed valve in the sensing line. Further investigation revealed a closed needle (dampening) valve. It was concluded that the needle valve vibrated closed to the point of maintaining pressure between the valve and the pressure transmitter after actual impulse pressure had significantly decreased. The signal from this impulse pressure transmitter does not indicate in the MCR.

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The dampening valve in question had been installed early in plant life to control an inherent problem with impulse pressure swings on Westinghouse Electric Corporation, 1,800 revolutions per minute turbines. This valve was routinely left nearly closed to sufficiently dampen the impulse pressure swings and allow use of the IMP IN mode of turbine control.

Discussions with Westinghouse concurred that the EHC system did respond as designed to what it thought was a mismatch between turbine impulse pressure (the postulated turbine load signal of approximately 100 percent) and the actual megawatt load electrical, which was approximately 60 percent.

The entry into LCO 3.0.3 was a result of two RPIs in control bank D deviating from the corresponding demand position indicator by more than 12 steps. The Unit 2 entry into LCO 3.0.3 resulted from an RPI drift associated mainly with instrumentation calibration bow and a reduction in area temperature at the RPI stack coils. The instrumentation calibration bow is an inherent design problem. This bow is a result of converting the alternating current stack signal to a direct current linear signal. Past experience has revealed that rod steps versus output voltage is not totally linear with the greatest deviation near 150 steps. The reactor head temperature change was a result of reducing power from 100 percent to near zero power and is a normal occurrence under these conditions. The indicated RPI position is influenced by stack coil resistance. Any temperature changes would affect the resistance of the coils and their subsequent output. It was concluded that the combination of error because of instrumentation calibration bow and temperature change had been sufficient to cause drift outside the maximum allowed 12 steps deviation. Because this RPI drift was determined not to be a calibration problem, the work requests generated were later cancelled.

ANALYSIS OF THE EVENT

These events are being reported in accordance with 10 CFR 50.73(a)(2)(iv) as an event that resulted in an automatic actuation of engineered safety features and in accordance with 10 CFR 50.73(a)(2)(i) as an operation prohibited by technical specifications.

As the governor valves closed at 200 percent per minute the reactor rod control system initiated a rod insertion and the steam dumps opened to compensate for rapid load reduction. Both rod control and steam dumps controlled as designed.

Steam generator and feedwater flow control systems performed properly. The rapid level drop in the steam generators (as a result of a rapid increase in steam header pressure), which occurred upon governor valve closure, caused feedwater regulator valves to open and main feedwater pumps to rapidly increase flow. Additional inventory was rapidly added to the steam generators, which quickly swelled as a result of heat addition from the RCS. The resulting steam generator level swell was to rapid to be stopped by the steam generator level control system. Although the system was responding to this swell, it did not stop the high-high level trip. Initially steam generator levels dropped to approximately 18 percent with Loops 3 and 4 indicating as low as 13 percent. The trip time delay (TTD) feature was in service because reactor power was below 50 percent. The rapid steam generator swell after the turbine trip was almost stopped by manual action before reaching the high-high level setpoint. Loops 1 and 2 increased to 79 percent and Loop 4 caused the engineered safety feature (ESF) actuation as its level to 82 percent. The Loop 3 chart did not ink on the rapid upward swing. Levels decreased to approximately 33 percent and were maintained by auxiliary feedwater.

The rapid changes in steam generator levels were also reflected in changes in RCS pressure. During the rapid steam generator level reduction, RCS pressure increased rapidly to approximately 2,390 psig. As the steam generator level rapidly recovered and continued to increase above normal levels, RCS pressure dropped to as low as 2,085 psig. The action provision of LCO 3.2.5, which requires pressure to be increased above 2,205 psig within two hours, was applied from 1515 EST to 1525 EST because RCS pressure was less than 2,205 psig.

During the event, all three No. 3 HDT pumps tripped. This occurred as a result of LCV-6-106B binding. This valve was later found to be 50 percent open when its controller was indicating zero output (full closed). The load drop that caused low flow to the No. 3 HDT caused the tank level drop as the system continued to pump forward through the failed LCV-6-106B. This resulted in a low level pump trip from the No. 3 HDT. This low level trip is designed for pump protection and performed as designed.

The turbine and generator tripped on a reverse power generator trip. The turbine first out alarms indicated both auto stop oil and turbine overspeed were the initiating trip. The first out annunciator only looks at turbine trips. because the initiating trip was a generator trip, it does not show on this panel. The electrical typer did confirm the reverse power trip. Low auto stop oil was a normal first out because the oil system is depressurized to close the turbine valves on an electrical fault.

The turbine overspeed resulted from steam still trapped in the low pressure turbine because the turbine valves and the PCBs tripped at the same time. This is to be expected because the governor valves are not designed to fully stop steam flow and the throttle valves got their signal to stop steam flow at the same instant that the PCB trip signal occurred.

The components that failed are nonsafety-related components. Their failure in itself has no adverse affect on plant safety. The results of their failure did challenge a safety function (AFW). The resulting ESF actuation performed as designed. All three AFW pumps started, delivered flow, and controlled level as required. The plant remained in a safe condition and at no time was the health and safety of the public or the plant in danger.

The entry into LCO 3.0.3 was a result of two RPIs in control bank D deviating from the corresponding demand position indicator by more than 12 steps. The Unit 2 entry into LCO 3.0.3 resulted from an RPI drift associated mainly with instrumentation calibration bow and a reduction in area temperature at the RPI stack coils. The RPI drift that was experienced can be expected following transients of this kind because of inherent sensitivities of the system design. The plant remained in a safe condition and at no time was the health and safety of the public or the plant in danger.

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CORRECTIVE ACTIONS

The immediate corrective actions for this event were to stabilize the plant and to align plant systems to their normal Mode 2 configuration. This included the repair of the No. 3 HDT level control valves. The importance of correctly assembling the valves in accordance with procedures was discussed with the involved maintenance personnel. The performance of these valves is being monitored in efforts to improve overall plant reliability.

The short-term corrective action to prevent recurrence of the EHC anomalies was to place administrative controls that prohibit the use of IMP IN unless specifically authorized by plant management. Verification of correct control signals would be made before allowing the use of IMP IN. Turbine manual control, which does not rely on process inputs for governor valve position control, could also be used to reset the EHC system panel.

As additional enhancements to prevent events of this nature, Operations is evaluating the depth and frequency of EHC failure training to identify additional training requirements. A training module on the EHC system will be incorporated into the Week 2 Operator requalification training. Operations is also evaluating the need to proceduralize the process for resetting the EHC system following turbine runbacks.

Four parallel actions were initiated to correct the RPI drift. A higher priority was placed on the work requests for the RPI. The Unit 2 crew was directed to reduce ventilation cooling to the reactor head area because temperature changes in this area had caused RPI drifts in the past. Voltage was lowered on the 161 kilovolt switchyard to lower shutdown board voltage that also had affected RPI drift in the past. Additional RCS boration was initiated to raise the control rod position. These actions were sufficient to return the RPI output to tolerance.

Because of the inherent bow in the RPI calibration curve, excessive drift can be expected at anytime the rods are positioned in the vicinity of 150 steps withdrawn. Excessive RPI drift following secondary side transients has not been routinely experienced at SQN, because reactor trips normally occurred following secondary side transients of this magnitude. Because of the implementation of the steam generator level environmental allowance modifier (EAM) and trip time delay (TTD) features, however, maintaining the reactor in Modes 1 or 2 with control bank D inserted is much more likely following secondary side transients as evidenced by this event.

SQN will conduct an evaluation in an effort to prevent future entries into LCO 3.0.3 as a result of RPI drift. This evaluation will consider alternative methods for monitoring control rod position (e.g., P-250 plant process computer) and controls for minimizing the time that rods are positioned in the vicinity of the most severe calibration bow.

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ADDITIONAL INFORMATION

A review of previous LERs indicated that ten feedwater isolations have been initiated by high-high steam generator level. None of these events were the result of transients initiated by anomalies in the turbine EHC system (SQN 50-327/84006, 84007, 84013, 84033, 85026, 85030, 88025, 88041, 88047, Revision 1, and 89035). Four of the LERs were the result of manual feedwater control during plant startups. Two LERs reported FWI signals generated during shutdown testing of steam generator level transmitters. Another two were the result rapid swells in steam generator level following the opening of a main steam isolation valve, and a spurious opening of a steam dump valve. One LER was the result of a leaking feedwater regulator valve that allowed the steam generator to be overfed. Only one of the LERs was associated with a secondary side transient following a turbine runback. During the event, feedwater flow was manually increased to offset steam generator level shrink. This prevented the steam generator level control system from adequately responding to the subsequent steam generator level swells.

Two LERs (50-327/85009 and 89026) have been submitted as the result of LCO 3.0.3 entries for multiple RPIs in the same bank being inoperable. One LER was the result of water intrusion into a line voltage regulator in the cable spreading room. The second LER was the result of temperature fluctuations induced by manipulations of the CRDM cooler. Procedural guidance was developed following the event to alert personnel to the potential RPI operability impacts of manipulating CRDM cooling. This guidance was adhered to during the evolution described in this LER.

COMMITMENTS

1. Operations is evaluating the depth and frequency of EHC failure training to identify additional training requirements. This evaluation will be completed by February 15, 1991.

2. A training module on the EHC system will be incorporated into the Week 2 operator requalification training by March 1, 1991.

3. Operations is evaluating the need to proceduralize the process for resetting the EHC system following turbine runbacks. This evaluation will be completed by March 1, 1991.

4. SQN will conduct an evaluation in an effort to prevent future entries into LCO 3.0.3 as a result of RPI drift. This evaluation will be completed by May 3, 1991.

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