NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Sequoyah, Unit 2

DOCKET NUMBER (2): 0 5 0 0 0 3 2 8

PAGE (3): 1 OF 11

TITLE (4): Engineered Safety Feature Main Steam Line Isolation and Reactor Trip Due to Maintenance Activities and Inherent Instrument Response During Steam Plant Heatup

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 NUMBER(S)
0 2	0 7	8 8	8 8	— 0 0 6 —	1	0 9	0 1	8 8		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 4

POWER LEVEL (10): 0 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)	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 AREA CODE	
K. W. Fenn, Plant Operations Review Staff	6 1 5	8 7 0 - 6 2 5 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) XX NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

This report is being revised to provide updated details concerning corective action completion dates. On February 7, 1988, at 2141 EST with unit 2 in mode 4, main steam isolation occurred and a reactor trip signal was generated by the engineered safety feature (ESF) actuation system. The signal was generated because the symptoms of main steam line break existed - low steam generator (S/G) pressure, low-low average reactor coolant system (RCS) temperature, and a high steam line flow signal. The S/G pressure and RCS temperature conditions existed because the unit was in mode 4. The high steam line flow signal was generated when opening the main steam isolation valves due to the inherent design of the steam flow program generator and maintenance in progress. The reactor trip signal coincident with a low RCS temperature caused a main feedwater isolation (MFI). When the main steam isolation valves (MSIVs) closed, the S/G levels experienced "shrink" to the low S/G setpoint. Coincident with the low S/G level, the steam flow/feedwater flow mismatch bistable was tripped in loop 4 for maintenance. This resulted in a second reactor trip signal. The plant stabilized, the MFI was reset, and then one MSIV was attempted to be opened at 2353 EST. This resulted in S/G level "swell" above the high-high S/G level setpoint. The high-high level resulted in a turbine trip signal and a second MFI. The causes of these events are improper compliance with procedures, nuance between operating procedures, human factor engineering of main steam pressure gauges, a steam dump valve not fully seated, and maintenance activities not fully evaluated for plant evolutions in progress. As corrective actions, the procedure has been changed, procedures are being recategorized, temporary instrumentation was installed for steam pressure measurements, the steam dump valve positioner was adjusted, and a plant statement has been made to address maintenance activities for protective equipment.

IE22 1/1

DESCRIPTION OF EVENT

This report is being revised to provide updated details concerning corrective action completion dates. Particularly, the corrective actions for the high steam flow setpoint calculator evaluation and the inspection of the main steam system downstream of the main steam isolation valves.
On February 7, 1988, at 2141 EST, unit 2 was in mode 4 (0 percent power, 475 psig, 270 degrees F), an engineered safety feature (ESF) (EIIS Code JE) signal was generated by the reactor protection logic (EIIS Code JC) which resulted in a main steam line (EIIS Code SB) isolation and a reactor trip signal being generated when an attempt was made to open all the main steam isolation valves (MSIVs). The reactor trip signal coincident with a low reactor coolant system (RCS) (EIIS Code AB) temperature resulted in a main feedwater (EIIS Code SJ) isolation. Subsequent to the determination of the causes of these signals, an attempt was made to open one MSIV at a time, starting with loop 4. At 2353 EST, RCS (EIIS Code SB) pressure was 470 psig and RCS average temperature was 265 degrees F, when the loop 4 MSIV was opened and resulted in a steam generator level "swell" above the high-high level setpoint. When the high-high level setpoint was exceeded, a turbine trip signal and a feedwater isolation signal resulted. The following report provides a chronological synopsis of the activities leading up to the events.

Initial plant conditions - unit 2 was in operational mode 4, the reactor trip breakers were tagged open, and the main turbine (EIIS Code TA) was on its turning gear. The main feedwater regulation valves were closed, and the feedwater regulation bypass valves were open. The condensate system (EIIS Code SD) was on long cycle, and a vacuum was in the condenser (EIIS Code SG). A non-nuclear heatup was in progress using the loop 1, 2, and 4 reactor coolant pumps augmented with the residual heat removal (RHR) system (EIIS Code BO) to control temperature.

In accordance with General Operating Instruction (GOI)-1, "Plant Startup from Cold Shutdown to Hot Standby," preparation was being made for a series of tests to be conducted on February 8, 1988. At 0001 EST, an Instrument Maintenance test director (TD) had notified the unit 2 assistant shift supervisor that he was prepared to begin backfilling the sensing lines of the loop 4 steam generator train "B" flow transmitter (FT 1-28B) and level transmitter (LT-3-106). Backfilling of these sensing lines was required by Work Request (WR) B279965 written on February 6, 1988, because the high steam flow loop 4 reactor protection bistable tripped while no high steam flow signal was present. The backfilling was being done via the performance of Maintenance Instruction (MI)-19.1.4, "Backfilling Sensing Lines for System 1 and System 3 Transmitters located on Panel L-183 (Fan Room 1)." When attempting to backfill the flow transmitter, the TD discovered that no service air (EIIS Code LF) was available to support the backfilling procedure.

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

The TD subsequently contacted the shift supervisor (SS) to determine why the service air was unavailable. The SE informed the TD that service air was isolated to support mode 4 and would not be immediately returned to service. During their discussion, it was decided to return the flow transmitter to the normal in-service configuration and then change the work instruction to allow use of a pump in lieu of air pressure to perform the backfill. At 0257 EST, the unit 2 reactor operator was notified by the TD that they were out of the test for the shift.

At 1244 EST, the steam generator blowdown system (EIIS Code WI) was aligned to the flash tank to provide additional temperature control. At 1258 EST, both trains of RHR pumps were removed from service in accordance with GOI-1 to perform Surveillance Instruction (SI)-166.18, "RHR Return Valve Leak Rate Test." At 1301 EST, the number 4 reactor coolant pump was stopped to decrease the heatup rate. At 1830 EST, the unit 2 assistant shift supervisor was notified by the TD that the backfill of the loop 4 steam generator level and flow transmitters was being resumed. At 1839 EST, Operations placed the steam dump system (EIIS Code JI) in manual with the steam dump valves closed. At 1859 EST, both trains of RHR were placed in standby following the completion of testing. At 1905 EST, the loop 4 reactor coolant pump was restarted to continue heatup in preparation of the warmup of the main steam system. At 1930 EST, the TD was testing the level and flow bistable switches in accordance with MI-19.1.4. At this time, all associated bistable switches were tripped. The bistable switches were to remain tripped during the performance of backfilling the sensing lines, in accordance with MI-19.1.4. At 1946 EST, the MSIV warming valves were opened to warm up the main steam header and to blow down the steam traps in accordance with System Operating Instruction (SOI)-1.1, "Main Steam Supply." This condition remained until the differential pressure across the MSIVs was considered to be less than 25 psid.

At 2141 EST, the 25 psi differential pressure requirement was met, and the control room operator proceeded to open all four MSIVs simultaneously in accordance with SOI-1.1. When the operator opened the MSIVs, the steam generator level "swelled" (from 50 percent to approximately 65 percent of steam generator level), and a high steam flow signal was generated. The high steam flow condition, coincident with the low steam line pressure (setpoint less than 600 psig) and low-low average RCS temperature (setpoint less than 540 degrees F), which was in affect due to plant conditions, made up the required logic for an engineered safety system steam line isolation signal and an associated reactor trip signal to the reactor protection system. When the reactor trip signal was generated, coincident with the low RCS temperature, the feedwater isolation logic was satisfied, resulting in a feedwater isolation signal. The MSIVs closed, as designed, resulting in the steam generator level experiencing a "shrink" to a level below the low level bistable trip setpoint of 25 percent.

When the steam generator low level bistables tripped, the required logic was satisfied with the coincidence of the steam flow/feedwater flow mismatch bistable tripped by the TD backfilling the loop 4 steam generator flow transmitter, to generate another reactor trip signal.

At 2159 EST, the operators began decreasing the RCS pressure to allow placing RHR in service. At 2206 EST, the loop 4 reactor coolant pump was stopped to decrease the heatup rate. At 2209 EST, the reactor trip breakers were cycled and the feedwater isolation signal was reset. The unit 2 reactor operator then contacted the TD and requested him to return the bistables, tripped by his procedure, back to normal. The bistables were back to normal at 2231 EST. The SS assessed this condition and reported it to the NRC operations duty officer at 2254 EST. At 2239 EST, the RCS depressurization was terminated at 440 psig.

Following stabilization of the first event, Operations decided to open only one MSIV at a time, starting with loop 4. When the loop 4 MSIV was opened at 2355 EST, the steam generator "swelled" to approximately 80 percent level. At 75 percent of steam generator level, the steam generator high-high level bistables trip, generating a turbine trip signal and a feedwater isolation signal which occurred as designed. The steam generator level immediately returned to approximately 50 percent following the transient. MSIV-2, MSIV-1, and MSIV-3 were subsequently opened at 0000 EST, 0005 EST, and 0006 EST on January 8, 1988, respectively. At 0011 EST, the reactor trip breakers were cycled and the feedwater isolation was reset. At 0019 EST, NRC operations duty officer was notified of the second event.

CAUSE OF EVENT

The immediate cause of the main steam line isolation and initial reactor trip was:

a. The RCS average temperature was less than 540 degrees F, and the main steam line pressure was less than 600 psig.

and

b. A high steam line flow signal was generated from at least two of the four steam generators when the MSIVs were opened.

The design bases of the main steam isolation signal is isolating a main steam line break located downstream of the MSIVs and check valves and to shut down the reactor. By design, the ESF actuation system senses this event by a high steam line flow and a low RCS average loop temperature or a low steam header pressure. The main steam line isolation logic requires inputs from two of the four loop steam line flows high (measured flow greater than program setpoint) and two of the four loop steam line pressures low (less than 600 psig) or a low-low average temperature (less than 540 degrees F). The plant temperature at the time was 270 degrees F, and the steam generator pressure was approximately 29 psig, which made up half of the required logic. The remaining half of the logic required for actuation was two of the four high steam line flow signals.

To complete the MSIV isolation logic, a high steam line flow condition was required on two of the four steam lines. One of the four high steam line signals was generated by the TD when the loop 4 flow switch was placed in the trip condition. The final signal came when the MSIVs were opened. The reason for the final signal has been attributed to the inherent behavior of the instrumentation associated with the high steam line setpoint program. The setpoint is programmed at 40 percent steam flow from 0 percent power to 20 percent power and is programmed at a constant slope from 20 percent power to 100 percent power. The power input to the setpoint calculator is derived from turbine impulse pressure transmitter. When turbine impulse pressure is 0 psig, as it was during this event, the quality of the signal is not sufficient to maintain the 40 percent setpoint and trends to drop it. During the conditions of this event, only one of the remaining three steam generator flow signals was required to cause a main steam isolation actuation. When all MSIVs were opened, steam flow signals were generated to combine with the low program setpoint to complete the main steam line isolation logic.

The immediate cause of the initial feedwater isolation was:

a. A reactor trip signal was generated by the ESF actuation signal when it sensed a main steam line break.

and

b. The average RCS temperature was less than 554 degrees F.

Isolating feedwater is a part of the design to preclude a cold water accident to the reactor due to an associated positive reactivity inherent to the reactor core design when the RCS is overcooled and to limit the cooldown rate.

Since the reactor trip signal was generated by the ESF actuation system when it sensed the symptoms of a main steam line break, and since the plant was at 270 degrees F, the required logic was satisfied to provide a feedwater isolation signal.

The immediate cause of the second reactor trip signal generation was:

a. The steam generator levels were less than 25 percent.

and

b. The loop 4 steam flow/feedwater flow mismatch bistable was tripped.

The steam flow/feedwater flow mismatch circuit is provided as an anticipatory reactor trip for an impending loss of steam generator water inventory. When the reactor protection system sensed a condition that more steam mass was exiting the steam generators than feedwater was entering and that the steam generator water levels were dropping, it generated a reactor trip signal in lieu of waiting for a reactor trip on low-low steam generator levels.

When steam flow is greater than feedwater flow by an amount above an acceptable value, the steam flow/feedwater flow bistables will trip to make up half of the required logic. If the steam generator levels decrease to 25 percent, the low steam generator bistables will trip, completing the required reactor trip logic. In this event, the steam flow/feedwater flow bistable for loop 4 steam generator was tripped during the performance of MI-19.1, and, the low level condition existed in the steam generators due to "shrink" when the MSIVs closed.

The immediate cause of the turbine trip and feedwater isolation signal was the steam generator level of 80 percent. The turbine trip and feedwater isolation signal is provided to protect the turbine from damage due to excessive moisture carryover experienced when any one steam generator level is to high.

A setpoint of 75 percent steam generator level is used to provide the protective signal. Since the steam generator reached 80 percent, the logic was satisfied. The cause of the high-high steam generator level was the "swell" experienced when the MSIV was opened. The "swell" experienced during this occurrence was exacerbated by opening only one MSIV, since it was steaming to a header normally supplied by four steam generators, and because one of the steam dump valves was not fully seated, allowing the steam piping to be exposed to the condenser vacuum. The steam dump valve was determined to be leaking based on upstream and downstream temperatures of the valve following the event. The leaking steam dump valve was caused by an improper valve positioner adjustment, which prevented it from fully seating. Positive valve position is not available in the control room.

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

The root cause of these events is primarily attributed to the lack of proper consideration between the affects of maintenance activities on plant evolutions. This is concluded because of the maintenance being performed on the steam generator level and flow transmitters and the schedule the operators were attempting to maintain with the plant heatup to support testing. Operations did not anticipate the impact on heatup rate from starting a second reactor coolant pump before the event, and it had been planned to use the main steam system as the heat sink. The plant was scheduled to remain at 250 degrees for a set period of time, but it was not recognized by personnel responsible for planning the evolution, however, that 250 degrees was the earliest possible temperature allowed by procedure GOI-1 to begin warming the steam system, let alone dumping steam. Since RHR had been secured and was not the method to be used to control RCS temperature, Operations personnel expedited placing main steam in service when temperature approached 270 degrees. This resulted in admitting full steam flow into a system not fully warmed.

Operations personnel and personnel responsible for planning the evolution perceived an atmosphere of expedience to complete plant evolutions. This perception, combined with the excitement surrounding the recent accomplishments of the project, resulted in actions which may not have been thoroughly analyzed before execution. The turbine trip signal and feedwater isolation may not have occurred if the cause of the first event was fully understood.

In addition to the schedule that Operations was attempting to maintain, the instrumentation and the classification of SOI-1.1 contributed to the event. The pressure gauges used by the operators to determine that the differential pressure across the MSIV is less than 25 psid have a scale of 0 - 1200 psig marked off at 20 psig increments. This instrumentation is not properly human factor engineered for an operator to determine the differential pressure is within 25 psi at a pressure of approximately 29 psig.

At Sequoyah, operating procedures that require step by step written instructions to be in hand and require verification signoffs are classified as Category "A" procedures. This classification is governed by Administrative Instruction (AI)-4, "Preparation, Review, Approval and Use of Site Procedure/Instructions." SOI-1.1 was not classified as a Category "A" procedure. This combined with the misunderstanding the operators had with compliance requirements with non-Category "A" procedures, led the operators to open the MSIVs prematurely. In addition to SOI-1.1's classification, some nuances were identified between SOI-1.1 and GOI-1 leading to further operator confusion.

ANALYSIS OF EVENT

These events are being reported under 10 CFR 50.73, paragraph a.2.iv, as events that resulted in automatic actuation of ESF.

The main steam isolation signal and reactor trip signal generated in the initial event is not considered to have an affect on the health and safety of the public. The main steam isolation logic generated a main steam line isolation signal and a reactor trip signal as designed. The closure of the main steam isolation valves was not required to isolate a main steam line break during this event but was a result of conditions symptomatic of a main steam line break. The generator of the reactor trip signal did not result in an actual reactor trip because the reactor trip breakers were tagged open previous to this event. The remaining engineered safety equipment that is required to start during an actual main steam line break did not start during this event because the P-4 permissive off the auxiliary contacts of the reactor trip breaker was activated, and by design, blocked the ESF signal. If these conditions occurred during power operation, the ESF actuation would have initiated as designed.

The feedwater isolation signal during the first event is not considered to have had a significant affect on the health and safety of the public. The feedwater isolation occurred because a reactor trip signal had been generated by the ESF actuation system in coincidence with the reactor coolant system average temperature less than 554 degrees F. The purpose of this feature is to preclude overcooling of the reactor coolant system following a reactor trip from overfeeding the steam generators. Overcooling following reactor operations can adversely affect the core by effectively adding positive reactivity which could result in an increase of core power production and can adversely effect the reactor coolant system via thermal stresses caused from high cooldown rates. During this event however, the initial conditions provided the low temperature condition, not a rapid cooldown rate, and the reactivity associated with the lower temperature is compensated by maintaining the required shutdown margin. The isolation of feedwater had no adverse affects on plant conditions because steaming of the steam generators was not in progress to deplete steam generator water inventory and core decay heat levels are low. If a cooldown was required, the feedwater isolation signal could be quickly reset to establish feedwater flow, and the RHR system was available to perform a cooldown. If an actual cooldown had occurred following a reactor trip from power operations, the main feedwater would have isolated as designed and the auxiliary feedwater system (EIIS Code BA) would have performed the primary heat sink function.

The reactor trip signal generated by the reactor protection system and the low steam generator water levels experienced from "shrink" are not considered to have had a significant effect on the health and safety of the public. The steam flow/feedwater flow mismatch coincident with low steam generator level is indicative of a condition of an impending loss of primary heat sink.

In this event however, the steam flow/feedwater flow mismatch was generated by manually tripping the bistables. No actual mismatch condition existed. The low steam generator levels in this event was not attributed to a loss of water mass in the steam generators, but due to a condition known as "shrink" which is inherent to the design of the steam generators during down power transients. An actual reactor trip did not occur as a result of this signal because the reactor trip breakers were tagged open previous to this event. If an actual loss of the primary heat sink had occurred during power operations, the reactor protection system would have generated a reactor trip signal as designed.

The turbine trip and feedwater isolation signal generated during the second event is not considered to have had an adverse affect on the health and safety of the public. The purpose of this feature is to protect the main turbine from damage due to water droplets impinging on the turbine blades that can be experienced when the steam generator water levels are too high. The turbine is tripped to prevent water from reaching the turbine blades, and the feedwater is isolated to preclude feeding an overfed steam generator. During this event however, an actual high level did not exist from a high mass inventory in the steam generator, and a turbine trip did not occur. The high-high steam generator level was a result of the steam generator experience "swell" which is inherent to the steam generator design during up power transients. This "swell" experienced during this event was exacerbated because only one MSIV was opened and was steaming to a main steam header normally supplied by four steam generators and from steam dump valve not fully seated. A turbine trip did not occur because the turbine was not in operation, it was on its turning gear. The isolation of feedwater had no adverse affects on plant conditions because steaming of the steam generators was not in progress to deplete steam generator water level, and core decay heat levels are low. If a cooldown was required, the feedwater isolation signal could be quickly reset to establish feedwater flow, and the RHR system was available to perform a cooldown. If an actual cooldown had occurred following a reactor trip from power operations, the main feedwater would have isolated as designed, and the auxiliary feedwater system would have performed the primary heat sink function.

CORRECTIVE ACTIONS

As immediate corrective actions, the control room operators assessed plant conditions subsequent to each event. Once determined to be a nonaccident condition, the feedwater isolation signal was reset.

To correct identified problems in SOI-1.1, the following procedural changes were made by revision 26 dated February 12, 1988.

1. The steam dump valves are verified to be closed before opening the MSIVs.

2. Portions of SOI-1.1 were reclassified as Category "A" instructions.

3. Instructions were provided to install and remove temporary narrow-range pressure gauges to measure the differential pressure across the MSIVs for low pressure conditions.

4. The RCS temperature requirements for initiating the warmup of the main steam lines and placing the main steam system in service was revised to be between 300 degrees F and 350 degrees F as required by GOI-1.

To address operator actions, training on this event and changes on Category "B" procedures to Category "A" procedures was conducted. This training was completed on February 15, 1988, via memorandum (S53 880303 879) to all Sequoyah Operations personnel.

To address instrumentation and equipment problems that contributed to these events, the following corrective actions were or will be taken.

1. An evaluation will be conducted to ensure the high steam flow setpoint calculator currently in use is adequate for compliance with technical specifications. A partial review has been performed which included an evaluation of the turbine impulse pressure transmitters (PT-1-72-73). However, a more encompassing evaluation of the total instrument loop is planned. This evaluation will be completed by September 30, 1988.

2. Narrow-range pressure gauges (50 - 300 psig) were installed to measure the differential pressure across the MSIV, as stated by SOI-1.1, Revision 26, to alleviate human factor problems when determining the differential pressure.

3. Steam dump valve FCV-1-105 was stroke adjusted on February 9, 1988, by WR B279990.

4. An inspection of the unit 2 main steam system, downstream of the MSIV, was made when the system was at normal operating temperature and pressure. This was completed on May 22, 1988.

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/88

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

To address the generic causes of this event, the following actions will be or have been taken.

1. A work control station has been established to control maintenance activities on components providing protective functions during plant evolutions affecting the subject components.

2. A review has been conducted to ensure that detailed instructions exist for evolutions, plateaus, and alignments required for modes 4 and 3 heatup.

3. An evaluation of all Category "B" SOIs will be made to determine if their categorization is appropriate as long-term enhancement program. Compliance requirements of Category "A" and "B" procedures are the same, and procedure deviations from either type is required to be documented.

4. AI-4 was revised (Revision 68) on February 15, 1988, to redefine Category "A" and Category "B" SOI usage.

ADDITIONAL INFORMATION

There has been one previous occurrence reported on MSIV closure due to ESF actuation signal - SQRO-50-327/85027.

There has been one previous occurrence reported on feedwater isolation resulting from steam generator high levels - SQRO-50-327/85026.

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*U.S. GPO: 1988-520-589:00070

TENNESSEE VALLEY AUTHORITY
Sequoyah Nuclear Plant
Post Office Box 2000
Soddy-Daisy, Tennessee 37379

September 2, 1988

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

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 2 - DOCKET NO. 50-328 - FACILITY OPERATING LICENSE DPR-79 - REPORTABLE OCCURRENCE REPORT SQRO-50-328/88006 REVISION 1

The enclosed revised licensee event report provides udated details concerning corrective action completion dates. This event was initially reported on March 5, 1988 in accordance with 10 CFR 50.73, paragraph a.2.iv.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

S. J. Smith

S. J. Smith
Plant Manager

Enclosure
cc (Enclosure):

J. Nelson Grace, Regional Administrator
U. S. Nuclear Regulatory Commission
Suite 2900
101 Marietta Street, NW
Atlanta, Georgia 30323

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

NRC Inspector, Sequoyah Nuclear Plant

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