Omaha Public Power District
P.O. Box 399 Hwy. 75 - North of Ft. Calhoun Fort Calhoun, NE 68023-0399
402/636-2000

August 3, 1992
LIC-92-146L

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, DC 20555

Reference: Docket No. 50-285

Gentlemen:

Subject: Licensee Event Report 92-023 for the Fort Calhoun Station

Please find attached Licensee Event Report 92-023 dated August 3, 1992. This report is being submitted pursuant to 10 CFR 50.73(a)(2)(iv), 10 CFR 50.73(a)(2)(ii), 10 CFR 50.73(a)(2)(i)(B) and 10 CFR 50.73(a)(2)(x).

If you should have any questions, please contact me.

Sincerely,

W. G. Gates

W. G. Gates
Division Manager
Nuclear Operations

WGG/lah

Attachment

c: J. L. Milhoan, NRC Regional Administrator, Region IV
S. D. Bloom, Acting NRC Project Manager
R. P. Mullikin, NRC Senior Resident Inspector
INPO Records Center

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NRC FORM 366 (6-89) 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)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	1 OF 1 9

TITLE (4)
Reactor Trip Due to Inverter Malfunction and Subsequent Pressurizer Safety Valve Leak

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 7	0 3	9 2	9 2	0 2 3	0 0	0 8	0 3	9 2	N	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 10 CFR §: (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, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	X 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Scott A. Lindquist, Shift Technical Advisor	4 0 2	5 3 3 - 6 8 2 9

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
B	E E	I N V T	E 2 0 9	Y					
B	A B	R V	C 7 1 1	Y					

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 July 3, 1992, at 2336, while the plant was operating at 100% power, the Reactor Protection System automatically tripped the reactor due to high pressurizer pressure. The event was initiated as a result of maintenance on a non-safety related inverter. During replacement of a degraded circuit board, power was momentarily lost to the instrument bus that supplies power to the Turbine Electrohydraulic Control System, resulting in closure of the turbine control valves. A subsequent failure of a pressurizer code safety valve resulted in high pressure in the pressurizer quench tank that blew the tank's rupture disk and resulted in the loss of approximately 21,500 gallons of contaminated water to the containment building sump.

The consequences of the event are bounded by the Fort Calhoun Station Updated Safety Analysis Report.

The root cause of the momentary loss of power to the instrument bus was determined to be the inability to isolate and test the non-safety related inverters after maintenance without potentially losing power to the respective 120V AC instrument buses. The root cause of the malfunction of Pressurizer Safety Valve RC-142 was determined to be the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out.

Corrective actions include a modification to enhance the ability to test the non-safety related inverters, addition of a positive mechanical locking device for the pressurizer safety valve adjusting bolts and completion of a comprehensive Recovery/Restart Action Plan.

BACKGROUND

The Reactor Protection System (RPS) monitors certain critical plant operating parameters and compares them to predetermined setpoints. If one or more of the monitored parameters reaches the setpoint on two of four channels, the RPS will initiate a reactor trip. There are twelve different reactor trips that can be initiated from the RPS. The trip unit of interest for this event is High Pressurizer Pressure.

The reactor trip for High Pressurizer Pressure is provided to prevent Reactor Coolant System (RCS) over-pressurization. In the event of a loss of load without a reactor trip, the temperature and pressure of the RCS would increase due to reduction in heat removal from the reactor coolant by the steam generators. The over-pressure trip setpoint is set at 2400 psia.

Two Power Operated Relief Valves (PORV) are designed to provide sufficient relief capacity during abnormal RCS pressure transients to prevent opening of the pressurizer safety valves. The PORVs are opened on High Pressurizer Pressure at 2400 psia. The valves are located in parallel pipes which are connected on the inlet side to a single relief valve nozzle on top of the pressurizer and to the relief line piping to the pressurizer quench tank on the outlet side. A motor operated isolation (block) valve is provided upstream of each of the PORVs to permit isolating a valve in case of failure or excessive leakage.

Two pressurizer code safety valves located on top of the pressurizer provide over-pressure protection for the RCS. They are totally enclosed, back pressure compensated, spring loaded safety valves meeting ASME code requirements. A loop seal is provided to minimize valve leakage.

The pressurizer quench tank is designed to collect and condense the normal discharges from the pressurizer during normal operation and to collect non-condensable gas discharges from the reactor vessel head or the pressurizer during post-accident situations. In either case, the pressurizer quench tank prevents RCS discharges from being released to the containment atmosphere. The steam discharged from the pressurizer is discharged underwater by a sparger to enhance condensation by uniform distribution.

The pressurizer quench tank can condense the steam discharged during a loss of load incident without exceeding the rupture disc setpoint, assuming normal blowdown of the relief valves at the end of the incident. It is not designed to accept continuous safety valve discharge. The pressurizer quench tank vents to the containment atmosphere following rupture of the rupture disk.

The 120V AC Instrument System is comprised of four safety related and two non-safety related buses, each supplied by a separate solid state inverter fed from a 125V DC bus. Each bus has a backup source of power via a 480/120V voltage regulating transformer. An inverter functions to electronically convert DC to a reliable source of AC power. Each inverter is equipped with a static switch that monitors the output of the inverter and automatically switches the load to the backup power source without a loss of power to the load if the inverter output is lost. A manual switch is available to bypass the inverter for maintenance.

Non-safety related Inverter #2 (EE-8Q) supplies power to 120V AC Instrument Bus #2 located in panel AI-42B which in turn supplies power to Turbine Electrohydraulic Control (EHC) Panel #2 (AI-50). The Turbine EHC system supplies the control signals to the turbine steam admission valves during startup, normal operation, shutdown, testing and transient conditions.

The Pressurizer Pressure Low Signal (PPLS) is initiated, in the event of a Loss of Coolant Accident (LOCA), at a pressurizer pressure of 1600 psia. When PPLS actuates the following actions are initiated:

1) A Containment Isolation Actuation Signal (CIAS) is generated.

2) A Safety Injection Actuation Signal (SIAS) is generated. SIAS in turn initiates a Ventilation Isolation Actuation Signal (VIAS).

3) The Emergency Diesel Generators are started.

4) Sequential starting of Engineered Safeguards and essential support systems equipment is initiated.

The Containment Isolation Actuation Signal (CIAS) is intended to prevent the release of radioactivity from the containment, especially in the event of an accident. Containment building piping penetrations are considered potential paths for the escape of radioactivity and are therefore, equipped with isolation valves. The CIAS is generated by a PPLS, or a Containment Pressure High Signal (CPHS). CIAS initiates the following actions:

1) Closes the containment isolation valves for flow paths which are not required to control or mitigate the accident.

2) Secures component cooling water flow through unnecessary heat loads.

The Safety Injection Actuation Signal (SIAS) automatically actuates safety injection in the event of a LOCA or Main Steam Line Break, to cover and cool the core and ensure adequate shutdown margin. SIAS is generated by a Pressurizer Pressure Low Signal (PPLS), or a Containment Pressure High Signal (CPHS). SIAS initiates the following actions:

1) High and low pressure safety injection loop injection valves open and emergency boration is initiated.

2) A Ventilation Isolation Actuation Signal (VIAS) is initiated.

3) Shedding of selected non-essential loads supplied from 480V motor control centers and shedding of complete 480V motor control centers serving loads which are not essential to support safeguards systems is initiated.

The Ventilation Isolation Actuation Signal (VIAS) is intended, in part, to prevent the release of significant radioiodine or radioactive gas from the containment to the atmosphere. One possible source of such nuclides could be reactor coolant leaks below the range that would be detected by coolant or containment pressure instrumentation. The VIAS is generated by an SIAS, a Containment Spray Actuation Signal (CSAS) or a Containment Radiation High Signal (CRHS). VIAS initiates the following actions:

1) Containment ventilation realigns to prevent a significant release of radioactive gas or particulates from containment.

2) Control Room ventilation shifts to the filtered air makeup mode.

3) Safety Injection Pump Room dampers reposition for safety injection pump operation.

The Containment Radiation High Signal (CRHS) radiation monitors detect gaseous and particulate radiation and provide alert and high alarms. CRHS is derived on a one out of five logic from separate contact outputs from each of five radiation monitors, Containment Particulate (RM-050), Containment Gas (RM-051), Stack Iodine (RM-060), Stack Particulate (RM-061) and Stack Gas (RM-062). CRHS initiates a Ventilation Isolation Actuation Signal (VIAS).

EVENT DESCRIPTION

At 0433 on July 3, 1992, with the plant in Mode 1 (Power Operation) at 100% power, the Fort Calhoun Station Control Room received an Inverter #2 Trouble Alarm. Inverter #2 had automatically transferred to the "Bypass" mode, which provides power from a 480/120V AC step-down bypass transformer through the inverter static transfer switch to Bus AI-42B. Upon placing the inverter in "Bypass", Bus AI-42B was declared inoperable due to being powered from its emergency source. Technical Specification Limiting Condition for Operation (LCO) 2.7(2)m was invoked with an eight hour time limit for restoring Bus AI-42B to its normal source of power. A priority one Maintenance Work Order was written to troubleshoot and repair the inverter, and Electrical Maintenance and System Engineering personnel were called out. By the time these personnel arrived, a Fan Failure Alarm on Inverter #2 had cleared. At 0636, Inverter #2 was returned to the inverter (normal) mode of operation and the Technical Specification LCO was cleared.

The Inverter #2 Trouble Alarm was received again at 1510 on July 3, and the inverter was transferred to "Bypass" for seventeen minutes before being returned to the Inverter mode. At 1921, the Inverter #2 Trouble Alarm was received for the third time. At this time, the inverter was manually bypassed by taking the Manual Transfer Switch from the "Static Switch" to the "Bypass" position. By manually bypassing the inverter, the DC input breaker to the inverter could be opened to allow troubleshooting and repair of the inverter. Two circuit boards in Inverter #2 were replaced, the Inverter Drive Board and the Static Switch Drive Board.

When placing an inverter back in service the operator must first close the DC input breaker, then place the Manual Transfer Switch back to the "Static Switch" position. He would then normally depress a "Forward Transfer" push-button, which would transfer power back to the inverter.

At 2335, when the operator placed the manual transfer switch in the "Static Switch" position, prior to depressing the "Forward Transfer" push-button, the static switch began cycling back and forth from the bypass transformer to the inverter. This caused Instrument Bus AI-42B voltage to oscillate between 0 and 120V AC. The operator immediately returned the Manual Transfer Switch to the "Bypass" position, restoring normal voltage to AI-42B. The voltage oscillations on AI-42B affected several pieces of equipment powered from AI-42B. Among the equipment affected was Toxic Gas Monitor YIT-6286B, which resulted in the tripping of all Control Room ventilation fans; and Breaker AI-42B-CB2 which tripped, causing a loss of power to the Electrohydraulic Control Supervisory Panel, AI-50. Although other equipment was affected by the voltage fluctuations, this had no significant impact on subsequent events.

Upon loss of power to AI-50, four pressure transmitter loops powered by Power Supply A-86 in the EHC Supervisory System became de-energized. The rest of the components in the system remained energized because they receive backup power from the Permanent Magnet Generator (PMG), which is driven directly off the Main Turbine shaft.

The four pressure transmitter loops which became de-energized, Throttle Pressure (PT-943), First Stage Pressure (PT-945), Initial Pressure Limiter (PT-939) and Power Load Unbalance (PT-944) provide input to the EHC Supervisory System for the purpose of modifying turbine control valve position under various conditions. When power was lost to these instrument loops, the output voltage from those transmitters (normally 0.1 to 5 volts DC) went to zero. This resulted in the control valve positioning units calling for a closed position on the valves. The sequence described above does not result in a turbine trip.

The closing of the turbine control valves resulted in a large mismatch between reactor power and steam demand. Since the Main Turbine did not trip, the Steam Dump and Bypass System was limited in its ability to respond to the Reactor Power/Steam Demand mismatch. The Steam Dump and Bypass System is a non-safety related system which normally acts to control RCS temperature and remove decay heat. However, it is designed for use primarily when the Main Turbine is off-line. While the Main Turbine is operating, the Steam Dump and Bypass System is limited to a modulation mode of operation, with a capacity of five percent steam flow.

The overall effect of the turbine control valves closing without significant steam dump and bypass capacity was to cause a sharp increase in RCS temperature. Pressurizer level, pressurizer pressure, and steam generator pressure also increased in response to the increase in RCS temperature.

At 2336, the reactor tripped due to High Pressurizer Pressure, and the PORVs and possibly Pressurizer Safety Valve RC-142 opened to lower RCS pressure. At approximately the same time, several main steam safety valves also opened. Upon receiving the reactor trip, the Main Turbine tripped, which enabled the Quick Open feature of the Steam Dump and Bypass System to rapidly open all steam dump and bypass valves to their full capacity of 38% steam flow. This reduced RCS temperature and pressure, allowing the PORVs and main steam safety valves to close.

At 2337 Fire Zone 33 (Room 81) went into alarm due to steam flow through the main steam safety valves.

For the first seven (7) minutes following the reactor trip, plant response was as expected for a load rejection event, and plant parameters were trending toward steady state post-trip conditions. Pressurizer pressure had reached a minimum of 1745 psia and was recovering, pressurizer level had reached a minimum of 33% and was recovering, and RCS temperature had stabilized at 532 degrees F. PORV tailpipe temperatures and pressurizer quench tank parameters indicated that the PORVs had opened, but the pressurizer quench tank parameters had stabilized, indicating that the PORVs had closed properly. The operators entered Emergency Operating Procedure EOP-00, Standard Post Trip Actions, and began to place plant systems in a normal post trip configuration. Since there was no indication of PORV leakage, the Primary System Operator elected to leave the PORV block valves open. A Containment Pressure Reduction, which had been in progress at the time of the trip, was secured at the direction of the Shift Supervisor.

At 2343, with pressurizer pressure at approximately 1923 psia, Pressurizer Safety Valve RC-142 lifted and RCS pressure began to decrease rapidly. At approximately 1020 psia, RC-142 apparently re-closed, but did not re-seat, resulting in a leak rate of approximately 200 gallons per minute through RC-142. RC-142 continued to leak throughout the remainder of the event.

At the time RC-142 opened, the operators were still completing their Standard Post Trip Actions. Upon observing lowering pressurizer pressure, the Primary System Operator closed the PORV block valves, and verified the valves indicated fully closed by limit switch indication. At this time, the Primary System Operator also noted that the RC-142 tailpipe temperature was in alarm. Pressurizer pressure continued to lower after the PORV block valves were closed, and at 1600 psia, a PPLS was generated, initiating actuation of Engineered Safeguards equipment (including High Pressure Safety Injection Pumps SI-2A, SI-2B and SI-2C, and Low Pressure Safety Injection Pumps SI-1A and SI-1B). The Primary System Operator verified that all Engineered Safeguards equipment had operated as expected for a PPLS actuation. At 2344, as RCS pressure fell below 1400 psia, the Primary System Operator tripped one reactor coolant pump in each loop as directed by EOP-00. The running turbine plant cooling water pump was load shed as a result of the Engineered Safeguards actuation. This caused the running instrument air compressor to shut down, and as a result a low instrument air pressure alarm was received.

As result of the PPLS actuation, the containment isolation valves supplying component cooling water to the reactor coolant pump seal coolers (HCV-438A, B, C and D) received a CIAS. The CIAS, combined with a momentary reduction in component cooling water pressure, resulted in HCV-438A through D closing. After verifying component cooling water pressure had returned to greater than 60 psig, the Primary System Operator re-opened HCV-438A through D. The duration of reduced component cooling water flow to the reactor coolant pump seals was 38 seconds, from the first valve coming off its open seat until the last valve was fully re-opened. There was no impact on the reactor coolant pump seals from this momentary reduction in cooling water flow.

At 2346, the Licensed Senior Operator completed EOP-00 and entered the Functional Recovery Procedure EOP-20. The transition was made to the Functional Recovery Procedure rather than the LOCA procedure because along with indications of a leaking safety valve, the status of AI-42B was not clear (three annunciator panels were de-energized, indicating that other problems may exist) and one pressurizer level indicator (LRC-101Y) was indicating zero (0) pressurizer level while the two other indicators were reading at or near 100%. It was subsequently determined that the erroneous readings from LRC-101Y were due to partial blockage of the reference leg tap. Immediately after entering EOP-20, the Secondary System Operator started a turbine plant cooling water pump, which allowed restart of the instrument air compressors. The Primary System Operator stopped two of the three high pressure safety injection pumps (SI-2B and SI-2C) after verifying that Safety Injection Stop and Throttle Criteria were met per EOP-20, Floating Step A.

Throughout the remainder of the event, the Primary System Operator adjusted high pressure safety injection flow to maintain greater than 20 degrees F subcooling at the highest temperature core exit thermocouple. Subcooling was monitored by plotting the maximum core exit thermocouple temperature and the low range pressurizer pressure (PI-118Y) on EOP Attachment 2, RCS Pressure-Temperature Limits. EOP Attachment 2 provides a manual means of plotting subcooling against a 20 degree F subcooling curve.

The Primary System Operator chose to use EOP Attachment 2 rather than the Emergency Response Facility Computer System (ERFCS) for subcooling indication, because he observed the ERFCS indicating zero subcooling with flashing question marks (denoting questionable data) at a time when he knew from various other indications that subcooling existed. The ERFCS indication of zero subcooling with a questionable data notation resulted from the ERFCS applying a conservative value of zero subcooling when high range pressure instruments (PI-120A/B) used in the subcooling calculation ranged lc Subsequent analysis of ERFCS printout data using wide range instruments indicate that from 2347 on July 3 until 0019 on July 4, the ERFCS indicated less than 20 degrees subcooling and from 2352 on July 3 to 0001 on July 4, the ERFCS indicated saturated or slightly superheated conditions existed in the RCS. The discrepancy between the ERFCS calculated value of subcooled margin and the EOP Attachment 2 plots was due to an apparent difference in RCS pressure values supplied to the ERFCS from Wide Range Pressure Instruments PI-105 and PI-115, and the low range pressure instrument (PI-118Y) used by the Primary System Operator. The Primary System Operator used PI-118Y as his pressure indication for subcooled margin because it was readily available on the control board and appeared to be tracking properly.

At 2349, the Primary System Operator secured the two remaining reactor coolant pumps as directed by EOP-20. At 2350, the Plant Manager was notified by the Duty Supervisor (who was on-site monitoring the Inverter #2 maintenance) of the event in progress.

At 2352, the Primary System Operator secured two charging pumps (CH-1B and CH-1C), to avoid the potential for RCS over-pressurization with the PORV block valves closed and uncertainty over the status of RC-142. Safety Injection Stop and Throttle Criteria were met (using EOP Attachment 2) at the time of charging pump shutdown.

At 2352, the Shift Supervisor declared an Alert classification based on Emergency Plan Implementing Procedure EPIP-OSC-1, Emergency Action Level (EAL) 1.10, Failure/Challenge to One Fission Product Barrier.

At 2353 on July 3, the Secondary System Operator took manual control of the Steam Dump and Bypass System in preparation for a rapid cooldown to shutdown cooling conditions.

At 2355, approximately 20 minutes into the event, the pressurizer quench tank rupture disk ruptured at approximately 75 psig. This resulted in Fire Zones 10 and 11 inside containment alarming, containment pressure, temperature and sump level rising (containment sump level would eventually reach a level of 12.5 ft. which corresponds to approximately 21,500 gallons) and slight increases in containment area radiation.

At 2358, Charging Pumps CH-1B and CH-1C were started to ensure boration criteria were met until a shutdown margin calculation could be performed. After determining that only one charging pump was needed to meet boration criteria, Charging Pumps CH-1B and CH-1C were periodically started and stopped throughout the remainder of the event.

At 0000 on July 4, High Pressure Safety Injection Pump SI-2B was restarted to provide additional injection flow. Additional safety injection flow was necessary to maintain RCS subcooling as RCS hot leg temperatures were increasing during establishment of natural circulation. At 0003, SI-2B was again secured.

At 0006, with containment temperature rising, Containment Cooling Units VA-7C and VA-7D were started to reduce containment pressure by providing additional cooling to condense steam in containment. Containment pressure peaked at 2.5 psig, and gradually decreased through the remainder of the event.

At 0010, notification of the states of Nebraska and Iowa was completed. The NRC Senior Resident Inspector was notified at 0020, and at 0029, the NRC Operations Center was notified of the event pursuant to 10 CFR 50.72(a)(3), via the Emergency Notification System, and an open line was maintained throughout the remainder of the event.

At 0012, the Shift Supervisor directed that a plant cooldown be initiated. Pressurizer pressure was approximately 1100 psia and RCS cold leg temperature was approximately 524 degrees F at the start of the cooldown. Supporting evolutions included inserting the non-trippable control element assemblies, restarting a condensate pump to refill the Emergency Feedwater Storage Tank, and performing a shutdown margin calculation.

At 0024, the hydrogen analyzers were placed in service, as required by the EOPs for High Energy Line Breaks inside containment.

At approximately 0030, an operator observed the acoustic flow monitor for RC-142 indicating flow. Two lights were lit (approximately 20% of scale), indicating RC-142 was leaking significantly, but was not fully open.

By 0050, with safety injection flow maintaining RCS pressure, the Operators began throttling safety injection flow. As the plant cooldown and de-pressurization continued, RCS and steam generator pressures continued to decrease. In accordance with the EOPs, the signal which initiates a Steam Generator Isolation Signal (SGIS) on low steam generator pressure (SGLS) was blocked at 0102 to prevent automatic closure of the main steam and feedwater isolation valves. At 0103 the Pressurizer Pressure Low Signal (PPLS) which initiated the SIAS was also blocked per the EOPs. This step is intended to initiate Low Temperature Over-pressurization Protection (LTOP) by enabling the LTOP function of the PORVs. Additionally, blocking PPLS would subsequently allow resetting of Engineered Safeguards equipment, which would allow restoration of certain normal system functions that are used during a cooldown. With the PORV block valves closed, however, LTOP protection could not be achieved. Due to concerns over the possibility of the PORVS not being reseated, the PORV block valves remained closed until 0334.

At 0110, all PORV and pressurizer safety valve acoustic flow monitors indicated zero flow.

At 0113, with pressure controlled, and well above the shutoff head of the low pressure safety injection pumps, SI-1A and SI-1B were secured in accordance with the EOP floating steps.

Normally, after a shutdown, auxiliary electric power to the non-vital buses is returned to the House Service Transformers by back-feeding through the Main Transformer. At 0119, following opening of the Main Generator disconnect switch, the Main Generator output breakers were closed to back-feed the non-vital buses. At 0122, the back-feed alignment was complete.

At 0131, with the Electric Driven Auxiliary Feedwater Pump supplying the steam generators, the Turbine Driven Auxiliary Feedwater Pump (FW-10), which started on PPLS/SIAS, was secured. Although no primary to secondary leakage was suspected, securing the pump minimized the potential for an unmonitored release from that source. At 0138, the manual isolation valve for the atmospheric dump valve was closed. Again, the Steam Dump and Bypass System was providing heat removal capabilities, and shutting the manual atmospheric dump isolation valve isolated a potential release path.

At 0146, Engineered Safeguards were reset, which allowed several desired actions over the next three hours:

1) The electric fire pump, which had started after fire header pressure decreased in response to the electrical load shedding of the jockey pump, was secured.

2) The Chemical and Volume Control System was restored to a normal configuration, which would allow the subsequent restoration of pressurizer level to the normal band.

3) The containment isolation valves for the containment gas and particulate monitors (RM-050/051), which had previously closed due to PPLS/CIAS, were re-opened to provide an indication of containment atmosphere conditions. At 0156, a CRHS was received from RM-050/051, initiating a second VIAS (VIAS had previously been initiated due to PPLS/SIAS) due to high containment activity. The VIAS re-closed the valves.

4) The steam generator and primary system sample valves were opened.

5) The Emergency Diesel Generators, which had started on the reactor trip were secured.

6) Auxiliary building ventilation was restored.

7) One of three component cooling water pumps was secured.

8) Two of the four raw water pumps were secured.

9) The motor control centers which had been load shed by the SIAS were re-energized.

At 0218, while attempting to lower pressure during the cooldown, the Primary System Operator observed possible reactor vessel head voiding over a period of approximately five minutes. The cause was likely inadequate cooling of the reactor vessel by natural circulation. The RCS was re-pressurized slightly, and the void collapsed. The lowest level in the reactor vessel head was 83% as indicated by the Reactor Vessel Level Monitoring System.

At 0329, with the Chemical and Volume Control System operating for RCS inventory control, the safety injection loop injection valves were fully closed. With these valves closed, makeup for RCS leakage was provided by the charging pumps only.

At 0334, PORV Block Valve HCV-151 (the isolation valve for PORV PCV-102-1) was re-opened. At 0337, PORV Block Valve HCV-150 (the isolation valve for PORV PCV-102-2) was re-opened. PORV tailpipe temperatures began increasing, so HCV-150 was immediately re-closed. With HCV-151 open, Low Temperature Over-pressurization Protection was re-established.

At 0406, a continuous fire watch was established in Room 81. Technical Specification 2.19(1) requires a fire watch to be established within one hour when specified fire detection instrumentation is inoperable. This requirement was not met within one hour of Fire Zone 33 going into alarm. Although a formal fire watch was not in place between 2337 (when the zone went into alarm) and 0406, several individuals, including fire watch qualified personnel, did enter Room 81 during this time.

At 0416, the fire alarms previously received for Fire Zone 33 (Room 81) and Fire Zones 10 and 11 (Containment) were reset. Technical Specification 2.19 requires a fire watch to be established if more than one fire zone in containment is inoperable, however due to containment conditions the watch was not established. Therefore, this Technical Specification requirement was not met while Fire Zones 10 and 11 were in alarm.

At 0420, the last high pressure safety injection pump, SI-2A was secured. At 0431, the safety injection tanks were isolated per EOP-20 to prevent injection as the RCS was de-pressurized in preparation for shutdown cooling.

At 0615, the containment isolation valves for the containment gas and particulate monitors (RM-050/051) were again opened to provide an indication of containment atmospheric conditions. The monitors remained in service for the remainder of the event.

At 0630, with RCS leak rate estimated at less than five gallons per minute the event was downgraded from an Alert classification to a Notification of Unusual Event with the concurrence of the NRC.

At 1024, one reactor coolant pump (RC-3C) was started to assist in cooling the reactor vessel head.

At 1053, preparations began for initiation of shutdown cooling and at 1312 shutdown cooling was established. EOP-20 was then exited and normal operating procedures for cold shutdown were implemented. The plant entered Mode 4 (Cold Shutdown) at 1825.

At 1840 on July 4, 1992, the Notification of Unusual Event was terminated.

This Licensee Event Report (LER) is being submitted pursuant to the following federal regulations:

1) 10 CFR 50.73(a)(2)(iv), due to the automatic actuation of numerous Engineered Safety Features including the Reactor Protection System.

2) 10 CFR 50.73(a)(2)(ii), due to the failure of RC-142 which resulted in the reactor coolant pressure boundary being seriously degraded.

3) 10 CFR 50.73(a)(2)(i)(B), due to the failure to establish fire watches in Room 81 and containment as required by Technical Specifications 2.19(1) and 2.19(2).

4) 10 CFR 50.73(a)(2)(x), due to containment conditions preventing the establishment of a fire watch patrol as required by Technical Specification 2.19(2).

5) 10 CFR 50.73(a)(2)(i)(B), due to previously unreported failures of Pressurizer Safety Valves RC-141 and RC-142 to meet Technical Specification 2.1.6(1) acceptance criteria during as-found testing performed in 1975, 1980, 1984 and 1985. (This was discovered during a detailed review of historical maintenance and testing records for RC-141 and RC-142.)

EVALUATION/SAFETY ASSESSMENT

The initial Nuclear Steam Supply System (NSSS) response to this event was a normal response to a load rejection event, and is bounded by the Updated Safety Analysis Report (USAR) accident analysis for a load rejection event. Peak RCS pressure was approximately 2430 psia, peak temperature of reactor coolant leaving the core was approximately 602 degrees F, and peak steam generator pressure was approximately 1033 psia.

USAR Section 14.15, Loss of Coolant Accident, indicates that a LOCA with an RCS break size of less than 0.5 sq ft is considered to be a Small Break LOCA. Using the nominal three inch size for the open Pressurizer Safety Valve (RC-142), the break size would be calculated as 0.049 sq ft. Therefore, by definition, this event was a Small Break LOCA.

The consequences of the event are bounded by the USAR analysis for a Small Break LOCA. The leak rate was greater than the 40 gallons per minute capacity of one charging pump while the RCS was at operating pressure. The Reactor Protection System functioned as designed to provide an automatic reactor trip and the Engineered Safeguards equipment actuated to cool the reactor core. The reactor core remained covered with coolant throughout the event. Post event analysis has determined that there are no apparent fuel rod failures in the reactor core. The fuel vendors have confirmed the maintenance of fuel integrity. During the event the ERFCS indicated saturated or slightly superheated conditions existed in the RCS for a period of approximately ten minutes. The fuel vendors have verified that there was no detrimental effect on the fuel or its integrity and that continued operation with existing fuel performance guidelines is acceptable.

The NSSS stress reports for key components have been reviewed and revised as required as a result of this event. The reactor vessel structural integrity was evaluated to ensure there were no pressurized thermal shock concerns from the High Pressure Safety Injection System operation or submerging the bottom of the reactor vessel. The results of the review and evaluation indicated no adverse impacts to the NSSS from this event.

Containment integrity was maintained throughout the event and containment pressure was maintained below three psig. Post-event containment releases were well within the requirements of 10 CFR 20.

The following average containment general area contamination levels were observed prior to the event (at the end of the last refueling outage), by initial survey after the event (on July 4, 1992), and following decontamination (between July 11 and July 15, 1992).

Containment Elevation	Pre-event (dpm/100 sq cm)	Initial Post-Event (dpm/100 sq cm)	Post-decontamination (dpm/100 sq cm)
1045'	1,186	87,751	16,691
1013'	1,263	39,740	972
994'	1,344	3,334,545	10,134

CONCLUSIONS

Following the event, investigations were initiated to determine the root causes of the momentary loss of power to Panel AI-42B and the malfunction of Pressurizer Safety Valve RC-142.

The following is a summary of findings regarding the failure of Inverter #2.

1) Both circuit boards which were replaced on July 3 (Static Switch Drive Board and Inverter Drive Board) were found to have components (ceramic resistors) that showed signs of discoloration due to overheating.

2) One of the resistors on the Static Switch Drive Board was found to have a bad connection which resulted in the connection being intermittent (i.e., making when it cooled off and breaking when it was hot). The bad connection of the resistor caused the inverter to go to the bypass mode three times in the same day.

3) When the Static Switch Drive Board was replaced, plant personnel failed to remove a metal jumper between terminal points 6 and 7 of TB204 on the old board and install it on the new board. The missing metal jumper caused the inverter to oscillate between Forward and Reverse.

4) A wire feeding the signal from the Static Switch Drive Board to the gate of Static Switch Inverter SCR12 in the inverter was found to be loose, thus not providing the signal to the gate of SCR12. It appears that this wire was unintentionally pulled off the gate during the replacement of the Static Switch Drive Board. The wire inadvertently pulled from the gate of SCR12, caused SCR12 not to gate on, resulting in zero voltage on the reverse side while silicone controlled rectifiers on the forward side were providing 120V AC. Therefore, the oscillation observed between Forward and Reverse caused a voltage fluctuation of 120V to zero (zero on the Reverse side and 120V AC on the Forward side) on Instrument Bus AI-42B.

The root cause of the momentary loss of power to AI-42B was determined to be the inability to isolate and test the non-safety related inverters (Inverters #1 and #2) after maintenance, without potentially losing power to the respective 120V AC instrument buses.

The following five contributing causes were identified with respect to the momentary loss of power to AI-42B:

1) Failure of vendor to inform utilities of potential for human error associated with the jumpers during board replacement,
2) Lack of a troubleshooting guide,
3) Poor workmanship during manufacture,
4) Single clad board design,
5) Unavailability of an inverter qualified Electrician.

NRC FORM 366A
(6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 3	— 0 0	1 5 OF 1 9

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

The significance of this event on the inverter is marginal. The troubleshooting activities and subsequent repair activities during the day and night of July 3, 1992, while ineffective in returning the inverter to service, did not significantly affect the long term operation of the inverter.

In order to address the malfunction of Pressurizer Safety Valve RC-142, both RC-141 and RC-142 were sent to Wyle Laboratories for a post-incident investigation of the failure of RC-142. The investigation revealed that only RC-142 had lifted and that it had sustained damage to its internals including indications of valve chatter and failure of the bellows assembly. One of the effects of this damage was to establish contact between the disc ring and the nozzle ring. This did not allow the valve to reseat properly, therefore the valve continued to leak. In addition, the valve setpoint adjusting bolt was found to be backed out, significantly lowering the valve setpoint.

The following is a postulated sequence of events regarding the failure of RC-142. Following the closing of the main turbine control valves, RCS pressure spiked to approximately 2430 psia. The PORVs and RC-142 opened, and then closed by the time RCS pressure had decreased to approximately 1750 psia. The inlet piping to RC-142 includes a loop seal with approximately 1.2 gallons of water. RC-142 is designed for steam service and will tend to chatter when relieving the loop seal volume. Although there may have been some initial chatter, the valve did close and RCS pressure began to recover. The pressure then recovered to approximately 1923 psia after approximately seven minutes. During this seven-minute period, the pressurizer quench tank level was stable, which indicates that RC-142 did fully close.

During the initial lift, it is postulated that valve vibration loosened the adjusting bolt locknut. This allowed the adjusting bolt to back off approximately one turn, thereby lowering the valve setpoint pressure to between 1900 and 2000 psia. The respective blowdown was also affected.

During the RCS pressure recovery, when the pressure reached approximately 1923 psia, RC-142 lifted again. This led to additional valve vibration and further reduction in the valve setpoint pressure and further changes in blowdown. The valve did not properly reseat and therefore continued to leak for the remainder of the event.

The root cause of the malfunction of RC-142 was the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out during valve actuation. Valve vibration during discharge caused the adjusting bolt locknut and adjusting bolt to turn. This lowered the set pressure of the valve and adversely affected blowdown.

The following two contributing factors were identified:

1) Inadequacy of the valve refurbishment procedure with respect to documenting the proper tightening of the adjusting bolt locknut.

2) The lack of a positive locking device to prevent the adjusting bolt from moving.

The failure of RC-142 had a significant impact on RCS inventory. Only the failure of Pressurizer Safety Valve RC-141 could achieve a similar impact on RCS inventory. Consequently, the issues concerning RC-142 failure are also being incorporated into RC-141. The adjusting bolt locknut or similar device is generic to many of the safety valves throughout the plant. However, no other safety valves incorporate a loop seal into their design which could result in the chatter which was a contributor to the failure of RC-142. In addition, the location of other safety valves relative to the RCS indicate that a similar valve failure would not result in a loss of RCS inventory and would therefore, be a much less significant event.

A review of historical maintenance and testing records was performed for RC-141 and RC-142. The review revealed that the "as-found" setpoints for Pressurizer Safety Valves RC-141 and RC-142 have been outside of +/- 1% of their respective set pressures on several occasions. Details are provided on the following list:

RC-141 setpoint is 2545 psia (2530 psig) +/- 1% (i.e., range of 2505 to 2555 psig)
RC-142 setpoint is 2500 psia (2485 psig) +/- 1% (i.e., range of 2460 to 2510 psig)

Year	Valve	"As-Found" Setpoint (psig)
1975	RC-141	2475
	RC-142	2453
1976	RC-141	2588
	RC-142	< 2317
1977	RC-142	2720
1980	RC-142	2548
1983	RC-141	2562
1984	RC-142	2592
1985	RC-141	2493
	RC-142	2434
1987	RC-141	2628

In each case, corrective maintenance required to return RC-141 and RC-142 to operability was completed. Technical Specification 2.1.6(1) indicates that the reactor shall not be made critical unless two pressurizer safety valves are operable with their lift settings adjusted to ensure valve opening between 2500 psia and 2545 psia +/- 1%. LERs were submitted in 1975 (LER 76-038), 1977 (LER 77 028), 1983 (LER 83-001), and 1987 (LER 87-014) reporting out-of-tolerance as-found test results, however, it appears that no LERs were submitted for out-of-tolerance as-found test results in 1975, 1980, 1984 and 1985.

Pressurizer safety valve test results are now reviewed as part of the relief valve program. This should prevent recurrence of a failure to report an out-of-tolerance condition. These unreported test results had no impact on the failure of RC-142 during this event.

In addition to the specific investigations of the Inverter #2 failure and the RC-142 failure, an overall investigation of the event was also conducted. One issue addressed in the overall investigation was the Turbine/Generator EHC System.

The EHC System original design had redundant power supplies, with normal power supply from an inverter and alternate power supply from the Permanent Magnet Generator (PMG). The PMG is driven by the turbine shaft and can supply an adequate source of power to the EHC system whenever the turbine is at rated speed.

In October of 1978, a design change modified the EHC System by replacing the original steam pressure transmitters with Rosemount transmitters. The original pressure transmitters were powered from the EHC panel and would continue to function in the event of a loss of power from the inverter because they had PMG backup power. When the new Rosemount transmitters were installed in 1978, they were supplied power from safety related Inverter "A" with no backup from the PMG.

On July 2, 1986, the failure of safety related Inverter "A" caused a transient similar to this event. At that time, the safety related inverters did not have the capability to automatically transfer to a bypass transformer for backup power, while the non-safety related inverters did. The corrective actions in 1986 included transferring the EHC panel from safety related Inverter "A" to non-safety related Inverter #2 so that an automatic backup power supply was available via fast transfer. The Inverter #2 failure on July 3, 1992 resulted in the loss of both primary and backup power to the pressure transmitters, which caused them to indicate zero pressure conditions. This caused the EHC System to close the turbine control valves, which resulted in a Loss of Load transient. This subsequently caused a reactor trip due to high pressurizer pressure similar to the 1986 trip.

The overall investigation concluded that addition of a second backup power supply to all EHC panel components from the PMG should be evaluated.

CORRECTIVE ACTIONS

As a result of this event OPPD developed a comprehensive Recovery/Restart Action Plan. Some of the points covered by the plan included investigation into system response, development and analysis of the sequence of events, evaluation of the transient's impact on the reactor vessel, assessment of potential equipment damage inside containment, incorporation of lessons learned into procedures, assessment of the effects of transients on mechanical systems, evaluation of the impact of high temperatures on systems, evaluation of fuel integrity, defining modifications to be performed, evaluation of reactor coolant pump seals and evaluation of non-safety related inverter loads. The Fort Calhoun Station was returned to power operation July 23, 1992 following completion of appropriate short-term corrective actions included in the Recovery/Restart Action Plan.

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

The following corrective actions have been or will be implemented as a result of the failure of non-safety related Inverter #2:

1) A modification has been installed which will allow isolation of the non-safety related inverters to perform maintenance and testing without losing the power to the 120V AC instrument bus.

2) An enhanced troubleshooting guide for all safety related and non-safety related inverters will be developed by January 1, 1993.

3) The wires leading to gates and cathodes of accessible inverter silicone controlled rectifiers (all six inverters) will be inspected, and soldered if required during the next refueling outage.

4) Training of Electrical Maintenance personnel regarding this event has been conducted. Lesson Plans for initial training for Electrical Maintenance personnel will be upgraded by September 30, 1992 to include lessons learned from this event.

5) Single clad circuit boards in the six inverters will be inspected during the next refueling outage for signs of degradation, and replaced if necessary.

6) Metal jumpers on inverter circuit boards will be replaced with wire jumpers by the end of the 1993 Refueling Outage.

The following corrective actions have been or will be implemented as a result of the failure of RC-142.

1) RC-142 has been refurbished and reinstalled.

2) A mechanical locking device has been added to the RC-141 and RC-142 adjusting bolts.

3) Adjusting ring and nozzle ring settings were reviewed to ensure optimum settings are being used for loop seal applications.

4) The effect on valve body temperature and valve setpoint pressure with the presence of valve insulation was investigated by installing temporary thermocouples on the valve and monitoring them during heatup and power operation. The temperature, as a result of the presence of the valve insulation, was found to have a negligible effect on the setpoint pressure.

5) A review of disc and nozzle materials which could be utilized to improve safety and performance of the pressurizer safety valves will be performed by December 31, 1992.

6) Further analysis will be completed, prior to the 1993 Refueling Outage, with respect to the failed bellows assembly removed from RC-142.

7) A review of the pressurizer safety valve testing procedures will be performed prior to the 1993 Refueling Outage to determine if changes are necessary (e.g., adding a routine back pressure test to verify bellows integrity, instructions for adjusting valve setpoint).

8) An evaluation will be performed by December 31, 1992 of the options for possible relocation of the pressurizer safety valves to eliminate the loop seal.

9) Lessons learned from the event will be incorporated into the relief valve testing program prior to the 1993 Refueling Outage.

The following corrective actions have been or will be implemented with respect to the EHC System:

1) Two turbine trips for loss of load have been installed. One will be actuated by a limit switch on Turbine Control Valve #1, when the valve approaches its closed seat. The other turbine trip will actuate when a Power Load Unbalance occurs.

2) An evaluation will be performed by September 30, 1992 to consider providing a second source of backup power (via the Permanent Magnet Generator) for EHC pressure transmitters.

PREVIOUS SIMILAR EVENTS

LER 86-001 reported a reactor trip resulting from the failure of a safety related inverter. On July 2, 1986 the Fort Calhoun Station reactor tripped due to High Pressurizer Pressure. The cause of the trip was determined to be loss of safety related Inverter "A" resulting in a loss of power to the turbine EHC panel. It was determined that on loss of EHC power, the turbine control valves shut but the steam dump and bypass valves do not actuate. A modification was installed to transfer EHC panel power to non-safety related Inverter #2.