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U.S. Nuclear Regulatory Commission
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Edwin I. Hatch Nuclear Plant - Unit 2
Licensee Event Report – Revision 1
Loss of Condenser Vacuum Leads to Manual
Reactor Scram and Engineered Safety Feature Actuations

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a loss of condenser vacuum which led to a manual reactor scram and engineered safety feature actuations. Revision 0 of this LER was submitted on July 14, 1999. Revision 1 is being submitted to correct an error in the original LER. It was stated that a ground occurred in a 600V cable when a recirculation system valve was closing. The ground actually occurred upon opening the valve. No conclusions or corrective actions are affected by the error.

Additionally, clarifications are provided on other items and a previous similar event, not mentioned in the original LER, is included.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

OCV/eb

Enclosure: LER 50-366/1999-006 Rev. 1

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IE22.

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NRC FORM 366 (06-1998) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Information and Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If a document used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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TITLE (4)
Loss of Condenser Vacuum Leads to Manual Reactor Scram and Engineered Safety Feature Actuations

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S)
06	15	1999	1999	006	01	10	26	1999	Plant Hatch, Unit 1	05000-321
										DOCKET NUMBER(S) 05000

OPERATING MODE (9)	1	POWER LEVEL (10)	041

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(vii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(ix)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

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COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
B	BO	PSP	G307	Yes		X	SB	SOL	H198	Yes
X	EA	RLY	None	Yes						

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On 6/15/99 at 2124 EDT, Unit 2 was in the Run mode at a power level of approximately 1540 CMWT (41 percent rated thermal power) and Unit 1 was in the Run mode at a power level of 2763 CMWT (100 percent rated thermal power). At that time, a manual scram was inserted on Plant Hatch Unit 2 in anticipation of receiving an automatic scram on a turbine trip due to loss of condenser vacuum. When the scram was inserted, an electric power transfer failed which should have automatically re-aligned Unit 2 4160-volt buses “C” and “D.” This further resulted in a trip of the Unit 2 reactor recirculation system pumps due to loss of lube oil pressure. When the recirculation system pumps were restarted, the “B” discharge valve began opening and activated an arcing ground fault on a 600-volt bus which is fed from Unit 1. The electrical noise resulted in several Unit 1 600-volt breakers tripping, including the feeder breaker to the reactor protection system power supply. This resulted in various engineered safety features actuating on Unit 1, including automatic closure of Group 2 primary containment isolation system valves. When condenser vacuum was broken on Unit 2 following the scram, bypass switches had not been reset, so the main steamline isolation valves automatically closed. However, one Unit 2 main steam isolation valve did not close as expected. The cause for the loss of condenser vacuum on Unit 2 was a combination of factors that led to the condenser being unable to reject sufficient heat. The cause of the failure of the power transfer was a relay being out of calibration. The cause for the ESF actuations on Unit 1 was a ground in a conductor supplying a Unit 2 load. The cause for the failure of the MSIV to close on demand was the failure of an AC solenoid operated pneumatic valve to shift positions when it was deenergized. Corrective actions for this event included the addition of a level instrument in the circulating water pump pit, promulgation of an operating order on condenser operating parameters, repair of the grounded conductor, and other items.

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PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 6/15/99 at approximately 1840 EDT, Unit 2 was in the Run mode at 2710 CMWT (98.1 percent rated thermal power) and Unit 1 was in the Run mode at 2763 CMWT (100 percent rated thermal power). At the time the level in the circulating water system (EIIS Code KE) flume was lowered in preparation for adding chlorine to the water. At approximately 2010 EDT, control room operators noted that generator output had decreased by about 10 megawatts. Investigation showed that condenser vacuum had decreased slightly and that the main condenser (EIIS Code SG) water box outlet temperature had increased unexpectedly. Reactor power was reduced to approximately 67 percent by reducing flow on the reactor recirculation system (EIIS Code AD). Concurrently, personnel were dispatched to check the water level in the flume. Flume level was found at levels believed to be acceptable. Differential pressures across the main condenser water boxes were also checked and found to be consistent across all the water boxes with all indications steady.

Despite the power reduction, water box outlet temperature continued to rise steadily, and the decay in main condenser vacuum began to accelerate. By 2110 EDT, Unit 2 load had been reduced to approximately 41 percent (1540 CMWT) by a combination of reduction in recirculation system flow and insertion of control rods (EIIS Code AA). At 2124 EDT, the low condenser vacuum annunciator alarmed in the control room. Therefore, the Shift Supervisor elected to insert a manual scram in anticipation of a trip of the main turbine (EIIS Code TA) on low condenser vacuum.

When the turbine was manually tripped following the scram, the main generator (EIIS Code TB) was automatically disconnected per design, and site loads should have automatically transferred to a transformer powered by an offsite source. However, two 4160-volt buses (EIIS Code EA), "C" and "D", failed to transfer due to a relay problem described later in this report. As a result of this, the lubricating oil pumps for the reactor recirculation system drive motor were deenergized. Therefore, the reactor recirculation system pumps tripped on low oil pressure. When licensed operators restarted the pumps, the recirculation pump discharge valves began to open as designed. During opening of the "B" valve, a ground on a 600-volt power cable manifested itself, and operators observed control room indication of the ground. These valves are powered from a Unit 1 power supply and as a result, when the ground occurred, electromagnetic interference was sensed in several Unit 1 600-volt systems, tripping breakers to the vital AC (EIIS Code EE) battery charger, various ventilation loads to the control building (EIIS Code NA) and intake structure (EIIS Code MD), and the motor-generator set which supplies division two of the reactor protection system (RPS, EIIS Code JC).

When one division of the Unit 1 RPS power supply tripped, several engineered safety feature actuations occurred on Unit 1. These included closure of outboard, small-bore Group 1 primary containment isolation

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system (PCIS, EIIS Code JM) valves, closure of various outboard Group 2 and Group 5 PCIS valves, isolation of secondary containment (EIIS Code NG), initiation of both trains of both units' standby gas treatment systems (EIIS Code BH), and shift of the main control room environmental control system (MCRECS, EIIS Code VI) to the pressurization mode. All these ESF actuations occurred as designed and were confirmed by control room operators using appropriate site procedures. Unit 1 systems were subsequently returned to configurations appropriate for full power operation.

When the scram was inserted, reactor water level decreased due to void collapse from the rapid reduction in power. However, due to the loss of the 4160-volt "C" and "D" buses, the condensate pumps and condensate booster pumps (EIIS Code SD) had no power and therefore were not available. This resulted in the reactor feedpumps tripping on low suction pressure; as a result, they could not be used to control reactor water level. Therefore, operators used the reactor core isolation cooling (RCIC, EIIS Code BN) system in the manual control mode to make up water to the vessel. The lowest reactor water level during the event was 20 inches below instrument zero (approximately 138 inches above the top of active fuel).

Several minutes after the scram, main condenser hotwell level was increasing due to the fact that steam was still being admitted to the condenser while the condensate pumps were deenergized, and condenser vacuum continued to degrade. Therefore, at approximately 2221, the Shift Supervisor directed that the outboard main steamline isolation valves (MSIVs) be closed to halt the steam flow. With the MSIVs closed, the safety/relief valves (S/RVs) were used to control pressure. No S/RVs were required to have opened automatically, and none did so. After controlling pressure using the S/RVs, operators noted that reactor water level was being adequately controlled by the RCIC system, so they chose to align the high pressure coolant injection (HPCI, EIIS Code BJ) system in the pressure control mode per procedure. In this mode, steam is expended in the turbine and exhausted to the suppression pool while water is recirculated in the condensate storage tank.

At approximately 2225, vacuum was broken in the main condenser. A full Group 1 PCIS actuation was received on low condenser vacuum. Three of the four open MSIVs closed as required; however, the "B" steamline inboard MSIV failed to close due to an AC solenoid valve which was stuck in the energized position.

Both the S/RVs and the HPCI turbine exhausted significant quantities of steam to the suppression pool. Therefore, the suppression pool temperature began to rise and licensed personnel in the control room aligned both divisions of the residual heat removal system (RHR, EIIS Code BO) to the suppression pool cooling (RHR/SPC) mode at approximately 2308. This mode requires energization of the residual heat removal service water (RHRSW, EIIS Code BI) system pumps whose discharge is piped to the RHR heat exchangers located in the lower diagonals of the reactor building. After the RHRSW system was energized, control room indications were received on high reactor building sump levels. A plant equipment operator was dispatched to investigate the source of the water and, at approximately 0150, he found a ¾-inch vent line broken off near the weld where it joins the RHRSW system process piping. Although the affected loop of suppression pool cooling remained operable, licensed personnel conservatively elected to secure the "A" loop to reduce the leakage volume being discharged into the reactor building diagonal. The opposite division of suppression pool cooling was maintained in service; however, the decrease in operating cooling capacity resulted in a slow warming of the suppression pool. The plant complied with the required actions for this condition as set forth in Unit 2 Technical Specifications limiting condition for operation 3.6.2.1. Unit 2 was brought to cold shutdown on 6/17/99 at 1000 EDT.

CAUSES OF EVENT

This event was initiated by a loss of vacuum in the main condenser. The loss of condenser vacuum, in turn, is believed to have resulted from a confluence of contributing causes which resulted in the condenser being unable to reject heat at a rate sufficient to accommodate the full power steam flow. These contributing causes were:

- air trapped in the condenser water boxes due to inadequate continuous vent design,
- reduced circulating water system flow due to lowering flume level for chlorination,
- slightly increased circulating water system temperature due to diversion of plant service water (PSW, EIIS Code KI) system flow,
- high humidity in the area of the cooling towers (EIIS Code KE) due to a local rain shower,
- less than adequate corrective action from a previous similar event occurring in 1995, and
- operating procedure limits on flume level not being met on June 3, 1999, which resulted in entraining air into the condenser water boxes.

These factors are explained in detail below.

The circulating water system flume is lowered on a frequent basis (5 to 7 times per week) for adding chlorine to the water. On June 3, 1999, flume level was lowered to the point that it reached the alarm setpoint and, it is believed, air became entrained in the circulating water flow. The air was then trapped in the condenser water boxes. Although the water boxes were recently equipped with continuous vents, a review of the piping layout has shown that the design of the continuous vents does not ensure successful venting. Therefore, the air in the water boxes could not escape and blocked water flow to some of the condenser tubes, reducing the heat rejection capacity of the condenser. This air is believed to have remained trapped in the water boxes for the next couple of weeks until other factors further reduced heat rejection capacity, resulting in the loss of vacuum and, ultimately, the scram.

On June 15, 1999, the day of the event, flume level was lowered around 1840 EDT for chlorine addition as usual. Per plant procedure, plant service water system effluent into the circulating water system was partially diverted. PSW effluent is somewhat cooler than the flume and enters the flume immediately upstream of the circulating water system pumps. With PSW flow diverted, the circulating water temperature entering the water boxes was slightly increased. In addition, with flume level lowered, circulating water system flow was slightly decreased due to reduced net positive suction head on the circulating water system pumps. Also immediately prior to the event, a light, local rain shower occurred. Although the shower did not significantly lower outside air temperature, it did decrease the cooling tower evaporation rate, contributing to a further rise in the inlet temperature of circulating water. As a result of all these factors, the exiting heat flux from the main condenser fell below the incoming heat flux from the main turbine. When this happened, condenser vacuum began to decline. Subsequent power reductions were not sufficient to recover vacuum.

In 1995, a similar event occurred on Unit 2 (LER 50-366/1995-003, dated 09/28/1995) in which a damaged cooling tower released fill material into the circulating water system flume. The fill material was caught by the circulating water system pump suction screens, partially clogging them. This reduced water level in the pump suction pit to the point that air was entrained in the flow, leading to air binding of the condenser water boxes. The Event Review Team (ERT) for that event recommended changes in flume level instrumentation and flume minimum operating level. These recommendations would have raised the low level alarm setpoint to 18 inches above the minimum pump submergence level and would have relocated the level instrument to the pump suction pit, providing a better indicator of pump submergence than a measurement taken upstream of the screens. With flume level at the alarm setpoint in effect during the 1995 event, the pumps began to lose submergence, entraining air in the flow. The ERT recommendation to raise the alarm setpoint was not implemented, so the setpoint was the same in the 1999 event as it was in 1995. Therefore, when the flume low level alarm was actuated during chlorination a couple of weeks prior to the scram, air was most likely trapped in the condenser water boxes, contributing to a loss of condenser capacity.

Also, the 1995 ERT recommended that flume minimum level be maintained where it would have provided sufficient pump submergence. The recommendation stated that flume level should be no lower than 117 feet MSL during chlorination. The operating procedure for the circulating water system was revised to maintain flume level between 116 and 118 feet MSL. Although this was a somewhat inaccurate implementation of the recommendation, it is believed that it would have been sufficient to have prevented the 1999 event had the limitation on level been strictly observed. However, two weeks prior to the event, the flume low level alarm was intermittently actuated for about half an hour. Since the alarm setpoint was at 114 feet MSL (as explained in the previous paragraph), it is evident that flume level was not being maintained between 116 and 118 feet MSL. The loss of submergence led to the entrapment of air in the condenser water boxes. In addition, the actual pump suction head could not be precisely determined because the recommendation to relocate the level instrument was not implemented.

The cause of the failure of 4160-volt buses "C" and "D" to transfer on demand was a "blocking" relay that was found out of calibration coupled with a slow reaction time of the 4160-volt breakers in the primary supply bus. The blocking relay is designed to prevent a bus transfer from occurring if the deenergized bus is without power for greater than 10 cycles at 60 Hz. This design feature prevents equipment damage from energizing a fully loaded electrical bus with the loads in an indeterminate state of coastdown. The relay had experienced a calibration drift which made it lock out too quickly. Therefore, by the time the fast transfer could be completed with breakers that were moving slightly slower than expected, the blocking relay had already tripped, aborting the fast transfer to the alternate supply. Subsequently, the bus was energized manually, the calibration of the relay having no effect on the manual power supply transfer.

The cause of the Group 1 PCIS valve isolation was that low vacuum bypass switches were not repositioned before breaking vacuum on Unit 2 following the unit shutdown. The Group 1 PCIS logic is designed to automatically close the MSIVs, the reactor water sample valves, and the main steamline drain valves whenever main condenser vacuum is being lost. This is designed to protect against an uncontrolled release of steam into the turbine building which could result from overpressurization of the condenser. This trip may be manually bypassed under control of procedure 34AB-C71-001-2S, "SCRAM PROCEDURE," by using switches in the main control room. In a normal plant shutdown, these switches are positioned to prevent a Group 1 PCIS actuation so that condenser vacuum can be relieved, providing braking action to assist turbine coastdown. In this event, the switches were not placed in the bypass position because personnel in the vicinity of the condenser heard banging sounds indicating possible flashing, and the need to break vacuum was urgent to prevent equipment damage. Not bypassing the low vacuum Group 1 isolation did not affect system isolation or event recovery since the outboard MSIVs were already closed. When condenser vacuum was manually broken using the vacuum breakers, a Group 1 PCIS actuation was received per plant design. At that point in the event, the outboard MSIVs had already been closed at the direction of the Shift Supervisor. Therefore, only the inboard MSIVs and small bore Group 1 valves were capable of responding to the signal. The small bore Group 1 valves and three of the four inboard MSIVs did close as designed. However, the "B" steamline inboard MSIV failed to close.

The cause of the Unit 2 "B" inboard MSIV failing to close was an electropneumatic pilot solenoid valve which stuck in the energized position. Each MSIV has three such solenoid valves, one powered from a direct current source and two from an alternating current source. The valve design requires one AC and one DC solenoid to deenergize in order for the MSIV to close on a Group 1 PCIS isolation signal. The second AC solenoid is used for testing. In this event, the AC solenoid stuck in the energized position. As a result, the pneumatic pressure on the MSIV actuator was not relieved, and the valve remained in the open position. The outboard MSIV in the same penetration was already closed at that time, so the safety function of isolating this penetration was successfully completed. The valve cluster was removed from the MSIV and sent to a contract testing laboratory for failure analysis. The analysis showed that the solenoid valve stuck because of a small particle of foreign material lodged between the top of the plunger and the mating surface of the stem. This debris prevented the plunger from reaching the home position when energized and caused the solenoid to buzz, deforming the plunger and resulting in mechanical binding of the plunger. The binding prevented the solenoid from changing state upon deenergization.

The cause of the trip of the RPS power supply on Unit 1 was a grounded conductor feeding the Unit 2 "B" recirculation system discharge valve. The power supply for this Unit 2 valve comes from a Unit 1 source.

The subject conductor is part of a steel-jacketed, armored cable. The steel jacket on the cable is intended to be grounded, and the circuit continuity of the ground connections is provided by special threaded fittings, each containing a crushable copper coil. When the segments are joined, a threaded nut with a ferrule-shaped inner core crushes the copper coil against the armor, ensuring a solid ground connection through the steel cable jacket. In this event, the fitting which was used was not the correct size for its application. As a result, during assembly, the copper coil did not slide up on the jacket as intended, but stayed around the conductors instead. When the threaded fitting was tightened, the copper coil bit into the cable insulation rather than the armor. The ground thus produced was an arcing ground which induced a wide spectrum of radio frequency (RF) electrical noise when the associated circuit was energized, as when stroking the valve. The RF noise affected the trip units in the 600-volt breakers previously mentioned, resulting in the trip units failing to their "safe," or tripped state per design. One of the breakers which tripped supplies the RPS motor-generator set. When the motor-generator set tripped, loads powered from the RPS power supply shifted to their "safe" or tripped state per design. Also, one of the breakers which tripped was of a type not previously observed to have been susceptible to electromagnetic interference (EMI). Because of this, the breaker and its trip unit were subjected to testing and inspection to ensure they were functioning properly. No anomalies were observed, and no further indications of grounds or faults have been observed on this bus despite extensive monitoring of the power quality. Therefore, it has been concluded that all the 600-volt breaker trip units on Unit 1 which actuated during the event did so as a result of EMI.

The cause of the failure of the ¾-inch vent line on the RHRSW appears to have been high cycle fatigue exacerbated by the piping geometry. The subject vent line was cantilevered off a section of large-bore pipe and has a manual valve located at the end of the vent line. As a result, normal piping vibration induced by system operation tended to concentrate stress where the vent line joined the system piping. This led to cracking, followed by crack growth and eventual breaking.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This event must be reported per 10 CFR 50.73(a)(2)(iv) because unplanned actuations of engineered safety features occurred both manually and automatically. Specifically, a manual scram was inserted in anticipation of a main turbine trip followed by an automatic scram. An arcing ground resulted in a trip of a 600-volt breaker which deenergized the reactor protection system power supply on Unit 1 with consequent closures of small bore Group 1 PCIS valves, Group 2 and Group 5 PCIS valves, isolation of secondary containment and initiation of both units' standby gas treatment systems. A Unit 2 Group 1 PCIS isolation occurred on low condenser vacuum when vacuum was manually broken without bypass switches being repositioned to prevent the isolation. An AC solenoid valve failed in the energized position, preventing an MSIV from going closed on a valid Group 1 PCIS signal.

The reactor protection system is designed to shut down the reactor by inserting a scram signal which causes all control rods to be rapidly and fully inserted into the core. Scram signals can be initiated on a number of process conditions such as high reactor pressure, low reactor water level, high neutron flux, etc. Scram signals can also be inserted manually by control room operators, which was the method of producing the

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reactor shutdown in this event. The scram functioned successfully and the reactor achieved a complete shutdown as designed.

The primary containment isolation systems on both units are designed to mitigate the consequences of a postulated accident in which fission products are released from the fuel into the reactor coolant or the drywell. The PCIS valves are grouped according to function and isolation signal. Group 1 PCIS valves are located in lines which communicate directly with the primary coolant system and are not required to be opened to mitigate the consequences of an accident such as loss of coolant accident (LOCA). Group 1 PCIS valves include the MSIVs, the reactor water sample valves, and the main steamline drain valves. These valves close on high drywell pressure or low water level (Level 1), steam tunnel or turbine building high temperatures, steamline high flow, and low condenser vacuum. In this event, a valid low condenser vacuum signal was received as a result of control room operators opening the main condenser vacuum breaker valves. Normally, this signal would have been bypassed as allowed by plant procedure. However, in this event, the signal was not bypassed, so the Group 1 valves received the isolation signal generated by low condenser vacuum. On both units, Group 1 PCIS valves closed as expected with the exception of the Unit 2 "B" steamline inboard MSIV which remained open due to a stuck valve relay. However, the redundant MSIV in the same piping penetration was already closed at that time. Therefore, the safety function of isolating the penetration was completed successfully.

Group 2 PCIS valves are those which communicate with the free space inside the drywell but which do not have direct connection with the primary coolant system. These valves include, among other things, isolation valves for drywell ventilation and leak detection. Group 2 valves close on signals including low reactor water level (Level 3) and various high radiation signals. Instrumentation which supplies trip signals for the Group 2 valves is powered from the RPS power supply through motor-generator sets. All Group 2 PCIS valves on both units responded per design given the signals which were applied to them. On Unit 2, the Group 2 PCIS valves received an isolation signal because of low reactor water level experienced during the scram transient. On Unit 1, the Group 2 PCIS valves received an isolation signal after the RPS power supply tripped because of electromagnetic interference with a 600-volt breaker trip unit resulting from a grounded cable. Since all the Group 2 valves on both units responded per design, the safety function of isolating the affected penetrations was completed successfully.

Group 5 PCIS valves are those located in the lines leading from the primary coolant system to the reactor water cleanup system. These valves close on a number of signals including low reactor water level (Level 2). On Unit 2, reactor water level of Level 2 was not reached during the scram transient; therefore, no Group 5 PCIS actuation occurred on that unit. However, on Unit 1, the loss of the RPS power supply resulted in one of two Group 5 PCIS valves going fully closed. This valve responded per design given the signal generated by the loss of power. Therefore, its safety function was completed successfully. The redundant valve in the same penetration did not receive an isolation signal because the power supply failure did not affect its isolation logic. Therefore, it remained open as designed.

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The secondary containment isolation system (SCIS) and standby gas treatment system are designed to mitigate the consequences of a postulated release of fission products into the secondary containment by drawing the building atmosphere through a set of filters, then exhausting the flow at an elevated release point via the main stack (EIIS Code VL). The SCIS consists of the Unit 1 and Unit 2 reactor building and common refueling floor along with isolation dampers which separate the buildings from the outside environment. The SGT system consists of fans, piping, ducts, dampers, and filters connected to the secondary containment on the suction side and main stack on the discharge side. The SCIS isolation and SGT initiation occur when instrumentation detects high radiation in the reactor building or refueling floor, or when a low reactor water level (Level 3) signal or high drywell pressure signal is generated. In the event of an accident involving the release of fission products into the secondary containment, the SCIS automatically isolates the ventilation dampers entering and leaving the secondary containment and deenergizes the normal building ventilation fans. The SGT system fans then automatically start, drawing the building pressure down to a specified vacuum (at least 0.2 inches of water column) to prevent any ground level release of fission products. The SGT flow then passes through charcoal filters for adsorption and holdup of fission products before being sent to the main stack. In this event, the SCIS and SGT system functioned per design given the signals generated by the low reactor water level on Unit 2 and the various signals generated by the loss of the RPS power supply on Unit 1. Since the SCIS and SGT system responded per design, the safety function was completed successfully.

When the manual scram was inserted on Unit 2, the 4160-volt buses "C" and "D" failed to transfer as required. This deenergized the condensate pumps and condensate booster pumps, resulting in the reactor feedpumps being unavailable due to low suction pressure. Therefore, the RCIC system was used as a source of high pressure makeup to the reactor vessel. The RCIC system consists of a steam turbine which drives a pump aligned to the reactor vessel through the necessary piping and valves. The RCIC system steam source is inboard of the MSIVs; therefore, it can inject even when a Group 1 PCIS actuation has been completed. The minimum reactor water level experienced during this event was above the setpoint for an automatic initiation of the RCIC system. The RCIC system was manually initiated by licensed control room operators during this event, as allowed by plant procedures, and functioned successfully to maintain level.

After the MSIVs were closed, the main condenser ceased to be available as a heat sink. Therefore, S/RVs were used for pressure control with the suppression pool being used as the primary heat sink, and the residual heat removal system being used to cool the suppression pool. The S/RVs are two-stage valves located on the main steamlines with their discharge vented to the suppression pool. There is a total of eleven such valves. The S/RVs can be actuated either mechanically or electrically by high pressure in the reactor vessel. In this event, all the S/RV actuations were manually controlled by licensed control room operators. The maximum pressure experienced by the plant during this event was below the automatic relief setpoints of the S/RVs; therefore, there were no automatic actuations of any S/RVs, nor should there have been.

As a proceduralized method of controlling reactor pressure, the HPCI system was aligned in a mode which allowed it to accept reactor steam while recirculating water to and from the condensate storage tank. The HPCI system consists of a steam turbine which drives a pump and is normally aligned via the necessary piping and valves to draw water from the condensate storage tank and inject it to the reactor vessel. The HPCI system is similar to the RCIC system, but has approximately ten times the pump capacity. The HPCI system can be operated in a mode to assist in control of pressure in the reactor vessel. In this mode, reactor steam is admitted to the turbine and exhausted to the suppression pool while water is drawn from the condensate storage tank and recirculated to the condensate storage tank through the test valve. The purpose of using the HPCI system in this mode is to retard the heatup of the suppression pool by reducing the energy in the steam admitted to the suppression pool. The energy is instead conveyed to the condensate storage tank in the form of pump heat. HPCI was not used to inject to the reactor vessel during this event because level was adequately controlled using the RCIC system. The minimum reactor water level experienced during the event was above the setpoint for an automatic initiation of the HPCI system. Therefore, there was no automatic HPCI injection to the reactor vessel, nor should there have been.

The broken ¾-inch vent line did not render the affected RHRSW system inoperable. Although water was escaping from the line, the volume of water was not sufficient to prevent the system from performing its intended function.

Based on the foregoing analysis, it is concluded that this event had no adverse impact on nuclear safety. This analysis applies to all operating conditions and power levels.

CORRECTIVE ACTIONS

An operating order has been issued for both units establishing more conservative operating limits on flume level, circulating water pump suction pit level, circulating water system temperatures, and condensate temperatures. These limits are intended to provide control room personnel with conservative parameters for plant operation.

The continuous vent system has been isolated with the exception of one water box on each unit which has its inlet valve closed and its outlet valve open. Manual venting will be performed using methods and timing indicated by plant procedures.

The grounded conductor in the Unit 2 drywell has been repaired. In addition, the affected 600-volt bus has been monitored by a power quality analyzer for several weeks and no evidence of another ground on the system has been observed. The period during which the system has been monitored included a plant startup, a scram on low reactor water level (reference LER 50-366/1999-007), a subsequent startup from that scram, and normal, steady-state full power operation. Although the repaired connection in the 600-volt cable has been evaluated by engineers and determined to be acceptable, it will be replaced during the next outage of sufficient duration.

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The 4160-volt fast transfer blocking relay has been replaced with a new relay from stock.

Periodic maintenance was performed on supply breakers for 4160-volt busses "C" and "D" using the plant's periodic maintenance procedure. The auxiliary breaker contacts which signal the automatic transfer logic were timed before and after the maintenance and found to be operating more rapidly. The alternate supply breakers for these busses will be refurbished as part of an ongoing program to address 4160-volt breakers generically. The scheduling for this action will be consistent with the nuclear safety significance of these breakers compared to others within the scope of the 4160-volt breaker program.

Procedure 34SO-N71-001-2N, "Circulating Water System," and the corresponding Unit 1 procedure have been revised to reflect the limits on the circulating water system that have already been published by the operating order. This action has been completed.

The ¾-inch RHRSW vent line has been replaced with a much shorter line and no longer has a valve on it. This will reduce metal fatigue and prevent recurrence of the piping failure. Further evaluations will be performed on the RHRSW drain valve 2E11-FD003 piping to determine if a modification to preclude metal fatigue failure is warranted. Also, vibration data were taken on accessible Unit 2 RHR, RHRSW, and HPCI vent and drain lines. The data will be used as input for an implementation plan to enhance the prevention of high cycle fatigue failures on susceptible systems for both units.

Water level indicators have been installed in the pump suction pits of both units' circulating water systems, observable in the control room. This modification has been completed.

Alarm setpoints for low flume level on both units have been changed to agree with previous recommendations.

Redundant circulating water pump suction screens have been removed from both units' circulating water systems in order to provide more net positive suction head to the pumps for any given flume level.

A possible modification will be evaluated to install instrumentation to measure condensate depression and display it continuously in the control room. This evaluation will be completed by 11/11/1999.

An audible buzzing check will be performed on the inboard and outboard MSIV solenoids prior to the next start-up from the respective refueling outages to ensure no debris is identified. Also, the need to replace the solenoid valve assemblies at staggered intervals to provide condition monitoring and earlier detection of problems will be evaluated.

A review of the plant's design change process will be performed to identify and correct problem areas which may make the plant vulnerable to receiving modification designs which fail to correct the problems they were intended to solve. Senior management will be briefed on the results of this review by 11/19/99.

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ADDITIONAL INFORMATION

1. Other Systems Affected: No systems were affected by this event other than those which have already been mentioned in this report.

2. Failed Components Information:

   Master Parts List Number: 2E11-FV003
   Part Name: Pipe
   Manufacturer: Gulf States Tube Corporation
   Manufacturer Code: G307
   Part Number: 0.750
   EIIS System Code: BO
   EIIS Component Code: PSP

   Master Parts List Number: 2B21-F022B
   Part Name: AC Solenoid Valve Cluster
   Manufacturer: Ralph A. Hiller Company
   Manufacturer Code: H198
   Part Number: SAA111
   EIIS System Code: SB
   EIIS Component Code: SOL

   Master Parts List Number: 2S32-K955
   Part Name: Time Delay Relay
   Manufacturer: ABB
   Manufacturer Code: None
   Part Number: 606B038A18
   EIIS System Code: EA
   EIIS Component Code: RLY

3. Commitments Information: This report does not create any permanent licensing commitments.

4. Previous Similar Events: There have been no events reported in the past two years in which a similar combination of causes produced a plant trip or other ESF actuations. The event most similar to this one occurred in 1995 (LER 50-366/1995-003, dated 09/28/1995) as previously mentioned in this report. In that event, corrective actions were recommended which likely would have prevented the 1999 event. Some of those corrective actions were not implemented because they did not address what was perceived to have been the primary cause of the event, which was the collapse of cooling tower fill material and subsequent clogging of the circulating water pump suction screens. One other corrective action from the 1995 event was the installation of continuous vents on the main condenser water boxes.

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As mentioned previously, the piping configuration used for that modification was not adequate. Another event occurred in 1997 in which it is believed that air binding in a main condenser water box resulted in a reactor scram. That event was reported in LER 50-366/1997-007, dated 5/8/1997. The corrective actions for that event included using a steam jet air ejector for the ensuing plant startup different from the one which had been in service during the scram, venting the main condenser water boxes, cleaning the suction screens for the circulating water system pumps, and instructing operators to maintain a certain level in the circulating water system pump suction pit. These corrective actions would not have prevented this event because they did not address all the different factors which led to this event.